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June 18, 2014

Re: Direct Testimony and Exhibits of Ezra D. Hausman on Behalf of Sierra Club (Redacted) -
Arizona Corporation Commission Docket Number E-01345A-11-0224

To Whom It May Concern:

Please find enclosed an original and thirteen (13) copies of the Direct Testimony and Exhibits of Ezra D. Hausman on Behalf of Sierra Club (Redacted). The confidential version of this filing is being served to parties that have executed Protective Agreements with APS.

Please let me know if you have any questions.

Sincerely,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing DIRECT TESTIMONY OF
EZRA D. HAUSMAN ON BEHALF OF SIERRA CLUB on all parties of record in this
proceeding by mailing a copy thereof, properly addressed with first class postage prepaid to:

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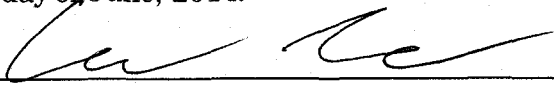
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Dated at San Francisco, California, this 18th day of June, 2014.



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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB STUMP, Chairman
GARY PIERCE
BRENDA BURNS
ROBERT L. BURNS
SUSAN BITTER SMITH

IN THE MATTER OF THE APPLICATION OF
ARIZONA PUBLIC SERVICE COMPANY
FOR A HEARING TO DETERMINE THE
FAIR VALUE OF THE UTILITY PROPERTY
OF THE COMPANY FOR RATEMAKING
PURPOSES, TO FIX A JUST AND
REASONABLE RATE OF RETURN
THEREON, TO APPROVE RATE
SCHEDULES DESIGNED TO DEVELOP
SUCH RETURN

DOCKET NO. E-01345A-11-0224

**NOTICE OF FILING TESTIMONY OF
SIERRA CLUB**

Sierra Club, through its undersigned counsel, hereby provides notice that it has this day
filed the written direct testimony of Ezra D. Hausman in connection with the above-captioned
matter.

//

//

DATED this 18th day of June, 2014.

/s/ Travis Ritchie

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Phoenix, AZ 85007

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served via first class mail this
18th day of June, 2014, to:

All Parties of Record

/s/ Travis Ritchie

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB STUMP, Chairman
GARY PIERCE
BRENDA BURNS
ROBERT L. BURNS
SUSAN BITTER SMITH

IN THE MATTER OF THE
APPLICATION OF ARIZONA PUBLIC
SERVICE COMPANY FOR A
HEARING TO DETERMINE THE FAIR
VALUE OF THE UTILITY PROPERTY
OF THE COMPANY FOR
RATEMAKING PURPOSES, TO FIX A
JUST AND REASONABLE RATE OF
RETURN THEREON, TO APPROVE
RATE SCHEDULES DESIGNED TO
DEVELOP SUCH RETURN

DOCKET NO. E-01345A-11-0224

REDACTED DIRECT TESTIMONY OF EZRA D. HAUSMAN, PH.D.

On Behalf of the Sierra Club

June 19, 2014

REDACTED

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I. Introduction

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Ezra D. Hausman, Ph.D. I am an independent consultant doing business as Ezra Hausman Consulting, operating from offices at 77 Kaposia Street, Auburndale, Massachusetts 02466.

Q. ARE YOU PROVIDING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring the following exhibits:

Exhibit No.	Content	Contains APS Designated Confidential Information
EDH-1	Resume of Ezra D. Hausman, PH.D.	No
EDH-2	Direct testimony of Mr. Patrick Dinkel on behalf of Arizona Public Service Corp., ACC Docket No. E-01345A-10-0474, Dated November 22, 2010.	No
EDH-3	APS response to Sierra Club Data Request 2.1	Yes
EDH-4	APS response to Sierra Club Data Request 2.4	Yes
EDH-5	APS response to Staff Data Request 35.35	Yes
EDH-6	"Greenhouse Gas Legislative Review and CO ₂ Price Outlook", prepared by Charles River Associates on behalf of Arizona Public Service Corp, and attached as Appendix A to APS's 2012 Integrated Resource Plan. Dated November 4, 2011.	No

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**Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL
BACKGROUND?**

A. I hold a BA in Psychology from Wesleyan University, an MS in Environmental Engineering from Tufts University, an SM in Applied Physics from Harvard University, and a PhD in Atmospheric Chemistry from Harvard University. I have been involved in analysis of both regulated and restructured electricity markets for more than 15 years. I have provided a detailed resume as Exhibit EDH-1.

From 2005 until early 2014, I was employed at Synapse Energy Economics, Inc., a research and consulting company located in Cambridge, Massachusetts, where I served most recently as Vice President and Chief Operating Officer. At Synapse, and continuing as an independent consultant, I served as an analyst and expert in several areas related to my expertise and experience in energy economics. Specific areas include:

- State and regional energy, capacity, and transmission planning, including both utility resource planning and long-term (multi-decadal) climate-constrained resource planning
- Electricity and generating capacity market design and analysis
- Electric system dispatch modeling
- Economic analysis of environmental and other regulations, including greenhouse gas regulation, in electricity markets
- Economic analysis, price forecasting, and asset valuation in electricity markets

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- 1 • Quantification of the economic and environmental benefits of displaced
2 emissions and market price impacts associated with energy efficiency and
3 renewable energy
- 4 • Regulation and mitigation of greenhouse gas emissions from the supply
5 and demand sides of the U.S. electricity sector

6 I have testified or appeared before public utility commissions and/or
7 legislative committees in Nevada, Maryland, Kansas, Louisiana, Missouri,
8 Mississippi, Vermont, Washington State, and Massachusetts, as well as at the
9 federal level. I have provided expert representation for stakeholders at the
10 PJM ISO and at the FERC. While most of my testimony and analytical work
11 has centered on issues in electricity market economics, I have also brought
12 my expertise as a scientist to bear on cases involving greenhouse gas
13 mitigation in the electric sector.

14 Prior to joining Synapse, I was employed from 1998 through 2004 as a
15 Senior Associate at Tabors Caramanis and Associates (TCA) of Cambridge,
16 Massachusetts. In 2004, TCA was acquired by Charles River Associates
17 (CRA), where I remained until I joined Synapse in 2005. At TCA/CRA, I
18 performed a wide range of electricity market and economic analyses and
19 price forecast modeling studies. These included asset valuation studies,
20 market transition cost/benefit studies, market power analyses, and litigation
21 support. I have extensive personal experience with market simulation,
22 production cost modeling, and resource planning methodologies and software.

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1 **Q. HAVE YOU EVER PARTICIPATED IN ANY RESOURCE**
2 **PLANNING PROCESSES CONCERNING ARIZONA PUBLIC**
3 **SERVICE COMPANY (APS)?**

4 A. Yes. In 2010, I participated in the stakeholder process supporting the
5 company's then-current resource planning process, on behalf of the Sierra
6 Club. I gave a presentation on June 18, 2010, on the monetization of
7 externalities in the resource planning process.

8 **Q. HAVE YOU EVER TESTIFIED BEFORE THE ARIZONA**
9 **CORPORATION COMMISSION?**

10 A. No.

11 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS**
12 **PROCEEDING?**

13 A. The purpose of my testimony is to bring to light certain aspects of APS'
14 recent acquisition of a large additional ownership share of Four Corners
15 Units 4 and 5 from Southern California Edison (SCE). I would like to bring
16 to the Commission's attention the fact that while APS's NPV analyses in this
17 case purports to show benefits to ratepayers from the acquisition relative to
18 other resource options, this analysis was based on limited and biased
19 information, and does not adequately support the company's conclusions.

20 APS originally filed for permission to pursue the Four Corners acquisition in
21 2010. Despite numerous changes in the underlying economic drivers forming

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1 the basis of APS's economic analysis since the original filing, the resulting
2 "benefit" to ratepayers on an NPV basis is remarkably similar: a \$426
3 Million NPV benefit claimed today, compared to a \$488 Million NPV benefit
4 claimed in 2010. However, based on my review of the company's data as
5 provided in its filing and in response to data requests, I conclude that
6 numerous decisions and assumptions were made that had the effect,
7 intentional or not, of making the acquisition plan appear to be more favorable
8 to ratepayers than it actually is. I show that many of these decisions
9 individually, if reversed, would have the effect of reversing the result of the
10 analysis, and revealing that the Four Corners acquisition is not in fact in the
11 interest of ratepayers. Taken together, these questionable assumptions mask
12 what is likely a very poor deal for ratepayers.

13 **Q. WHAT PARTICULAR ASPECTS OF APS'S ANALYSIS DO YOU**
14 **ADDRESS IN YOUR TESTIMONY?**

15 **A.** I address the following aspects of APS' analysis and underlying assumptions:

- 16 • **Fuel price forecasts.** The revisions made to APS's fuel price forecasts
17 for the updated analysis would, were no other changes made to the
18 underlying assumptions, make enough of a difference in the forward-
19 looking economics of the plant as to make it uneconomic. This is because
20 the expected future price for natural gas has decreased significantly in the
21 intervening years, while the company's expectation for the cost of coal
22 has increased. However, I find that the company has implausibly

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1 minimized the effect of these fuel price outlook changes by reverting to
2 its previous, higher gas price forecast just a few years in the future.

- 3 • **Carbon dioxide emission costs.** I find that APS misapplied its own
4 consultant's recommendations on the projection of CO₂ emission costs,
5 and departed dramatically from the company's own forecasts as applied
6 in the 2010 filing, without any explanation for its actions. As a result,
7 APS used unrealistically low price forecasts for both its "Base Case" and
8 "High Case" trajectories. My analysis shows that this anomalous
9 treatment of emissions costs accounts for the entire claimed savings
10 associated with the Four Corners acquisition in the current docket, and
11 possibly much more.
- 12 • **Capital expenditures.** I find that the unexplained changes in the stream
13 of projected capital costs for Four Corners between APS's 2010 filing
14 and the current docket are anomalous and counterintuitive, and are
15 starkly inconsistent with the changes in anticipated capital costs for other
16 resources—and as a result tend to bias the analysis strongly in favor of
17 the acquisition.
- 18 • **Other operational assumptions.** I find that APS continues to make
19 optimistic assumptions regarding the future performance of Four Corners,
20 projecting that the plant will run at a very high capacity factor through
21 2039. The company has apparently not considered the implications for
22 ratepayers in the likely event that this assumption turns out to be incorrect.

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1 **Q. WHAT IS YOUR RECOMMENDATION FOR THE COMMISSION?**

2 I recommend that at this time the Commission reject APS's request for an
3 increase to rate base of \$183.3 million, reflecting costs associated with the
4 purchase of SCE's share of Four Corners Units 4 and 5.¹ The Commission
5 should further condition any future approval of rate base adjustments
6 reflecting the Four Corners acquisition on APS re-filing its petition with a
7 revised analysis that is more detailed, and that provides a full explanation and
8 justification for the numerous changes in the company's assumptions and
9 projections since its 2010 filing.
10

11 **Q. ARE YOU SUGGESTING THAT THE COMMISSION RECONSIDER**
12 **ITS DECISION NOS. 73130 (DOCKET NO. E-01345A-10-0474) OR**
13 **73183 (DOCKET NO. E-01345A-11-0224)?**

14 No. In Decision No. 73130, the Commission authorized APS "if it so chooses"
15 (p.43 at 3) to pursue the acquisition of SCE's interest in the units, and to
16 defer the costs of this acquisition for later recovery through rates. The
17 Commission did *not* deem the acquisition to be prudent, nor did it offer APS
18 a blank check for either the purchase of Units 4 and 5 or for any additional
19 costs:

¹ Direct Testimony of Elizabeth Blankenship, 9 at 23.

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1 8. This Decision should not be construed to limit this
2 Commission's authority to review the acquisition of Four
3 Corners Units 4 and 5, or the unrecovered costs or additional
4 costs incurred in connection with the closure of Four Corners
5 Units 1-3 at the appropriate time, and to make disallowances
6 thereof due to imprudence, errors or inappropriate application of
7 the requirements of this Decision. (Decision 73130, p.42 at 19)

8 Order No. 73183 simply kept the relevant Docket open until December 31,
9 2013 so that APS could file the current request for rate treatment, but did not
10 in any way guarantee approval of that request.

11 Allowing costs associated with the purchase of SCE's ownership share of
12 Four Corners 4 and 5 into rate base exposes APS's ratepayers to new and
13 expanded risks and costs. The purpose of my testimony is to bring these risks
14 and costs to light, and to detail certain questionable assumptions and other
15 shortcomings in the company's NPV analysis. In light of these shortcomings,
16 APS has not made an adequate case that the acquisition is prudent, or that the
17 requested rate base increase is justified. I recommend that the Commission
18 hold APS accountable for its decision to move forward with this acquisition
19 despite significant changes in market conditions. In my opinion, the
20 company's petition in this docket cannot reasonably be approved based on
21 the analysis and evidence presented.

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1 **II. Background**

2 **Q. PLEASE PROVIDE BACKGROUND INFORMATION ON THE**
3 **FOUR CORNERS PLANT, AND ON APS'S DECISION TO ACQUIRE**
4 **SCE'S SHARE OF FOUR CORNERS UNITS 4 AND 5.**

5 A. The Four Corners Generating Station is a 5-unit, coal-fired power plant
6 located within the Navajo Reservation in Northwestern New Mexico. Units 1,
7 2, and 3, which had a combined capacity of 560 MW, began operation in the
8 early 1960s and were wholly owned by APS.² These units have now ceased
9 operation.

10 Units 4 and 5, which have a combined capacity of 1,540 MW, came online in
11 1969-70. Prior to December 2013, APS owned 15% of these units; 48% was
12 owned by Southern California Edison (SCE), a subsidiary of Edison
13 International that serves customers in much of southern California, and the
14 remaining shares are variously owned by Public Service Company of New
15 Mexico (13%), Salt River Project (10%), El Paso Electric (7%), and Tucson
16 Electric Power Company (7%).³

² Direct testimony of Mark A. Schiavoni on behalf of APS in Docket No. E-01345A-10-0474, pp. 2-3.

³ *Id.*, p.3.

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1 In 2010, SCE announced that it would not participate in any further “life-
2 extending” investments in the plant,⁴ pursuant to California Public Utilities
3 Commission (CPUC) rules intended to limit investments in electric
4 infrastructure with high levels of greenhouse gas emissions such as baseload
5 coal-fired electric power plants. Because Four Corners Units 4 and 5 will
6 require significant environmental upgrades to meet EPA emissions standards
7 by 2016,⁵ this rule meant that SCE would have to divest its 48% share of the
8 units. According to the 2010 testimony of APS witness Mark Schiavoni, had
9 SCE been unable to find a buyer for this share, the units would likely have to
10 be retired.⁶

11 From APS’s perspective, this situation presented an opportunity to shut down
12 the older, less efficient units 1-3, avoiding environmental upgrade costs on
13 those units, and to more than make up for the lost generating capacity by
14 assuming a greater share of the larger, less aged Units 4 and 5.

15 APS’s analysis presented in Docket E-01345A-10-0474 demonstrated
16 convincingly that retaining and investing further in Units 1-3 would be a poor
17 choice for the company and its ratepayers, and those units have since been
18 retired. APS witness Patrick Dinkel further argued that acquiring SCE’s

⁴ *Id.*, pp.5-6.

⁵ *Id.*, p.4-5.

⁶ *Id.*, p.6

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1 share of Units 4 and 5 at the agreed upon purchase price, and assuming the
2 increased cost of the required environmental upgrades on those units, was in
3 ratepayers' interest. Specifically, Mr. Dinkel's NPV analysis concluded that
4 there would be an expected NPV benefit to the acquisition of \$488 Million,
5 relative to the alternative of replacing APS's share of the energy and capacity
6 from Four Corners with new natural gas-fired combined cycle (CC)
7 generating units.⁷ However, because APS was under a "self-build
8 moratorium" (ACC Decision No. 67744) the company had to seek specific
9 authorization to purchase SCE's share of Units 4 and 5, independent of any
10 request for ratemaking treatment of the acquisition and other associated costs.
11 The Commission authorized the company to pursue the acquisition of SCE's
12 interest in the units, and further ordered that "Arizona Public Service
13 Company is authorized to defer for possible later recovery through rates, all
14 non-fuel costs...of owning, operating, and maintaining" the acquired
15 interest.⁸

16 Sierra Club intervened in Docket No. E-01345A-10-0474 and retained the
17 services of Mr. David Schlissel to review and provide expert testimony on
18 APS's filing. Among other issues, Mr. Schlissel highlighted the risk that the

⁷ Testimony of Patrick Dinkel, ACC Docket No. E-01345A-10-0474 (Exhibit EDH-2). See figure on "APS Customer Benefits", p.10.

⁸ Decision No. 73130, p.43.

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1 Four Corners plant will not operate in the future as long and/or at as high a
2 capacity factor as the company projects:

3 Although APS repeatedly emphasizes the risks posed by natural
4 gas price volatility, it ignores the risks associated with the
5 continued operation of the Four Corners Units 4-5 that are
6 currently over 40 years old, having entered commercial service
7 in 1969-1970. In particular, without any supporting evidence,
8 the Company very optimistically assumes that Units 4-5 will
9 continue to operate at very high levels of performance as they
10 age up to and beyond the age of sixty. (Direct testimony of
11 David Schlissel in Docket No. E-01345A-10-0474, 3 at 17)

12 APS has continued to ignore these and other risks in the current filing,
13 despite their very significant potential implications for ratepayers.

14 **Q. HAVE ANY CIRCUMSTANCES CHANGED SINCE THE**
15 **COMMISSION CONSIDERED THE FOUR CORNERS**
16 **ACQUISITION IN THE 2010 DOCKET?**

17 Yes. Since the company's initial filing, a number of important economic
18 factors have changed that affect the economics of the transaction. These
19 include:

- 20 • A reduction in the purchase price, due to a delay in the closing date of the
21 transaction between SCE and APS;

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- 1 • An increase in the expected cost of coal, pursuant to the sale of the coal
- 2 mine to the Navajo nation and a renegotiation of the coal purchase
- 3 agreement;
- 4 • A reduction in the expected cost of natural gas going forward;
- 5 • A change in the company's expectations with respect to the cost of
- 6 carbon emissions going forward;
- 7 • A change in the company's projection of capital requirements for the
- 8 maintenance of Four Corners Units 4 and 5;
- 9 • The duration of the period for which costs and benefits were calculated
- 10 was reduced from 30 to 25 years.

11 Many of these changes individually have an impact comparable to or larger
12 than APS's estimated NPV benefit of the Four Corners acquisition relative to
13 the closest alternative plan. However, other than the reduction in the
14 purchase price, the company has provided few or no details about the
15 rationale for these changes. Even more remarkable, the combined impact of
16 all of these very significant changes is almost no net change in the
17 company's assessment of the long term NPV benefit of the transaction for
18 consumers. The projected benefits changed from an estimated \$488 Million
19 over 30 years, as projected in 2010, to an estimated \$426 Million over 25
20 years as projected in the current filing.

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1 **Q. HAVE THERE BEEN CHANGES ELSEWHERE IN THE ELECTRIC**
2 **POWER INDUSTRY THAT HAVE BEARING ON THIS CASE?**

3 Yes. The coal industry across the country continues to face mounting
4 challenges. Throughout the United States, utilities are reconsidering the
5 economics of coal plant ownership in light of both fuel price dynamics and
6 impending and likely environmental regulations, and in many cases they are
7 divesting or shutting their coal assets—much as SCE elected to sell its share
8 of Four Corners. While SCE’s decision to exit Four Corners may have been
9 primarily motivated by California law, another owner, El Paso Electric, has
10 decided to divest itself of its 7% share of the very same Four Corners units at
11 issue here without any such regulatory requirement. In addition, BHP Billiton,
12 a huge multi-national mining company, decided to dispose of its ownership
13 in the Navajo mine that provides coal to Four Corners.

14 As another example of failing industry confidence in the economics of coal
15 plants, a recent proceeding before the Montana Public Service Commission
16 suggested that the Colstrip coal plant in Montana was a net liability. In an
17 application related to the purchase of hydroelectric assets from PPL Montana,
18 a merchant generator and part-owner of Colstrip, NorthWestern Energy
19 witness Brian B. Bird attested that “Northwestern bid \$400 Million for all

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1 [Colstrip and hydro assets] of PPLM...and \$740 Million for the Hydros..."⁹

2 This valuation suggests that NorthWestern set a *negative* \$340 Million value
3 on PPLM's coal assets in the proposed bid. Mr. Bird explained that this
4 negative valuation was due, in part, "...to recent Environmental Protection
5 Agency ("EPA") actions and uncertainty around the viability of coal-fired
6 assets in the future" including the risks associated with future remediation
7 costs.¹⁰

8 There are numerous other examples of coal units that have been recently
9 slated for retirement or conversion to natural gas. Of course, every unit,
10 every market, and every utility is unique. However, if APS is asking this
11 Commission to approve rate recovery for a decision that goes so strongly
12 against the industry trend, the company bears the burden to justify and
13 explain its decision in detail, and to demonstrate that it has done rigorous and
14 unbiased analysis in support of that decision. I do not believe that this
15 standard has been met in the current filing.

⁹ Direct testimony of Brian B. Bird on behalf of Northwestern Energy, Montana Public Service Commission Docket No. D2013.12.85, p. BBB-7.

¹⁰ Id., p. BBB-8.

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1 **III. Changes in Economic Outlook after 2010 Filing**

2 **Q. WHEN AND AT WHAT PRICE DID APS ORIGINALLY PLAN TO**
3 **ACQUIRE SCE'S SHARE OF FOUR CORNERS UNITS 4 AND 5?**

4 A. The initial petition specified a closing date of October 1, 2012, for a cash
5 price of \$294 Million.¹¹ This price was to decrease by \$7.5 Million for each
6 month that the closing was delayed.¹²

7 **Q. WHEN AND AT WHAT PRICE DID THIS TRANSACTION**
8 **ACTUALLY TAKE PLACE?**

9 A. The transaction actually closed on December 30, 2013.¹³ Because of the
10 delay in the closing date, the final purchase price was approximately \$181.5
11 Million.¹⁴

12 **Q. OTHER THAN THE CONTRACTUAL DECREASE IN THE**
13 **PURCHASE PRICE, HOW HAD MARKET CONDITIONS**
14 **CHANGED IN THE INTERVENING TIME?**

15 A. One important change in the expected market conditions was an increase in
16 the price of coal for the Four Corners plant. Another was a decrease in the

¹¹ APS *Application* in Docket No. E-01345A-10-0474, 22 at 10.

¹² Id., Footnote 108 on p. 22.

¹³ APS *Application* in Docket No. E-01345A-11-0224, 1 at 22.

¹⁴ APS did not readily provide the final purchase prices; I derived the value provided here by reducing the \$294 million price by \$7.5 million for 15 months. According to the testimony of Elizabeth Blankenship in Docket No. E-01345A-11-0224, Attachment EAB-10, the "Total Rate Base" impact of the acquisition is \$183,271,000.

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1 expected price of natural gas. Together, these reduce the long-term benefit of
2 the transaction to APS's ratepayers.

3 APS also reduced its expected values for the future cost of carbon emissions
4 between 2010 and the current filing, which would tend to increase the
5 expected benefits of the acquisition for ratepayers. Finally, APS appears to
6 have revised its projection of capital costs for maintaining the plant.

7 **Change in Expected Coal and Gas Prices**

8 **Q. HAVE YOU REVIEWED THE FUEL PRICE FORECASTS USED BY**
9 **APS IN DOCKET NO. E-01345A-10-0474 (2010) AND IN THE**
10 **CURRENT DOCKET?**

11 A. Yes. Gas and coal price forecasts used for the current filing were provided in
12 response to Sierra Club Data Request 2.1 (Exhibit EDH-3); Gas and coal
13 price forecasts used by APS in Docket No. E-01345A-10-0474 were
14 provided in response to Sierra Club Data Request 2.4 (Exhibit EDH-4). In
15 both cases the coal price forecasts were marked as confidential.

16 **Q. HOW DID APS'S COAL PRICE FORECAST CHANGE BETWEEN**
17 **THE COMPANY'S ORIGINAL APPLICATION AND THE ACTUAL**
18 **DATE OF THE ACQUISITION?**

19 A. CONFIDENTIAL Figure 1 compares the coal price forecast assumed by APS
20 when the company originally analyzed the Four Corners acquisition in 2010,
21 as used by APS witness Patrick Dinkel in his NPV analysis, with that

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1 assumed by the company in its most recent filing. On a levelized basis,¹⁵ the
2 price increased by about [REDACTED] from [REDACTED] between these
3 two forecasts.
4



CONFIDENTIAL Figure 1. Coal price forecasts used by APS witness Patrick Dinkel in 2010 vs. those underlying APS's analysis in 2014.

5 **Q. HOW DID APS'S GAS PRICE FORECAST CHANGE BETWEEN**
6 **THE COMPANY'S ORIGINAL APPLICATION AND THE ACTUAL**
7 **DATE OF THE ACQUISITION?**

8 **A.** Figure 2 compares the gas price forecast assumed by APS when the company
9 originally analyzed the Four Corners acquisition in 2010, as used by APS

¹⁵ Levelized on a nominal basis over the period 2015-2029, with a discount rate of 7.2%

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witness Patrick Dinkel in his NPV analysis, with that assumed by the company in its most recent filing. On a levelized basis,¹⁶ each price trajectory decreased by 14.3% between the two sets of forecasts. The levelized prices are shown in CONFIDENTIAL Table 1.

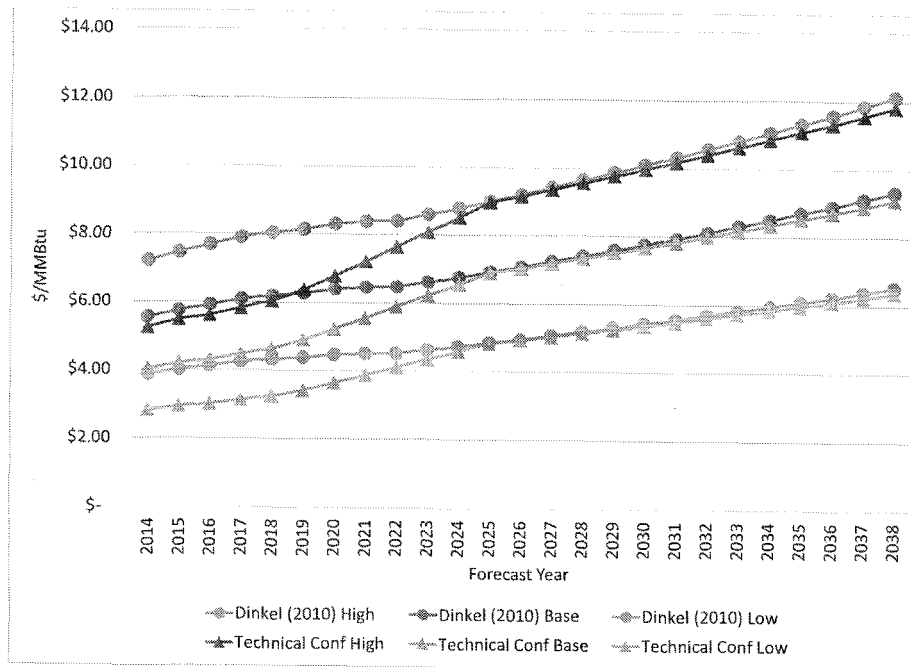


Figure 2. Gas price forecasts used by APS witness Patrick Dinkel in 2010 vs. those underlying APS's 2014 analysis.

¹⁶ Levelized on a nominal basis over the period 2015-2029, with a discount rate of 7.2%

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*CONFIDENTIAL Table 1. Comparison of APS's fuel price forecasts
levelized over the period 2015-2029 at a discount rate of 7.2%*

		Dinkel (2010)	Technical Conference (2014)	% Change
Gas				
Low	\$	(4.52)	\$ (3.87)	-14.3%
Base	\$	(6.46)	\$ (5.53)	-14.3%
High	\$	(8.39)	\$ (7.19)	-14.3%
Coal				
Base				

1 **Q. WHAT IS THE IMPACT OF THESE CHANGES IN APS' FUEL**
2 **PRICE FORECASTS BETWEEN 2010 AND THE CURRENT**
3 **FILING?**

4 A. The result of these changes is a significant reduction in the economic benefits
5 to ratepayers. In fact, I conclude that had APS used the company's later,
6 updated fuel price projections at the time of the initial filing, all else being
7 unchanged, the company would have found that the alternative plan of
8 retiring Four Corners entirely and replacing it with new gas plants was the
9 preferable option from an NPV perspective.

10 **Q. ON WHAT DO YOU BASE THIS CONCLUSION?**

11 A. In 2010, Mr. Dinkel concluded that in his "base case" analysis there would
12 be an NPV savings of \$488 Million from the company's preferred plan
13 (acquiring SCE's share of Four Corners) relative to the company's alternative.
14 I investigated the question: how much of this projected benefit would have

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1 been eliminated had Mr. Dinkel had the updated, 2014 fuel price forecasts
2 available to him?

3 Of course, I do not have access to the company's dispatch model, which
4 would be required to capture all of the dynamics of redispatch under different
5 economic conditions. However, as a first cut, I investigated instead how
6 much *larger* the projected benefits would be in the current filing if the fuel
7 costs under the current dispatch were adjusted using the fuel price forecasts
8 used by Mr. Dinkel in 2010, but without redispatching the system.

9 As summarized in Table 2, I estimate that the change in the fuel price
10 outlook would lead to an NPV change of almost \$500 Million. This suggests
11 that the effect of the change in forecasted fuel prices was more than enough
12 to negate the entire benefit claimed by APS either in 2010 or in the present
13 proceeding, had not APS made numerous other changes to different
14 assumptions that counteract this change.
15

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CONFIDENTIAL Table 2: Impact of Change in Fuel Price Forecast on NPV Benefit

	As Filed (\$Million)	Adjusted Fuel Cost (\$Million)
Alternative 1		
Four Corners 4,5		
Other		
Alternative 1 Total		
Alternative 2		
Four Corners 4,5		
Other		
Alternative 2 Total		
Fuel Cost Difference		
Implied impact on NPV Associated with Change in Fuel Price Outlook:		(\$498)

Q. DO YOU BELIEVE THAT THE COMPANY'S REVISIONS TO ITS FUEL PRICE FORECASTS WERE REASONABLE?

A. Only partly. I expect that the company's coal price outlook is accurate, at least for the duration of the current contract, as it is based on the renegotiated contract with the Navajo Nation for coal from the Navajo mine. However, I find the gas price forecasts, shown in Figure 2, to be more dubious. APS has incorporated the fact that natural gas is much less costly and more abundant today than had been expected prior to 2010, and in the early years of the company's forecast this is reflected in a reduction in the forecasted prices by about 25% relative to the 2010 forecast. However, this difference diminishes rapidly, until in 2025 there is no difference between the two forecasts – and very little difference thereafter (Figure 3). This is hard to reconcile with the general industry expectation of the long-term impact of new gas extraction

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1 techniques, and it is hard to imagine (nor has the company explained) what
2 the underlying rationale might be.

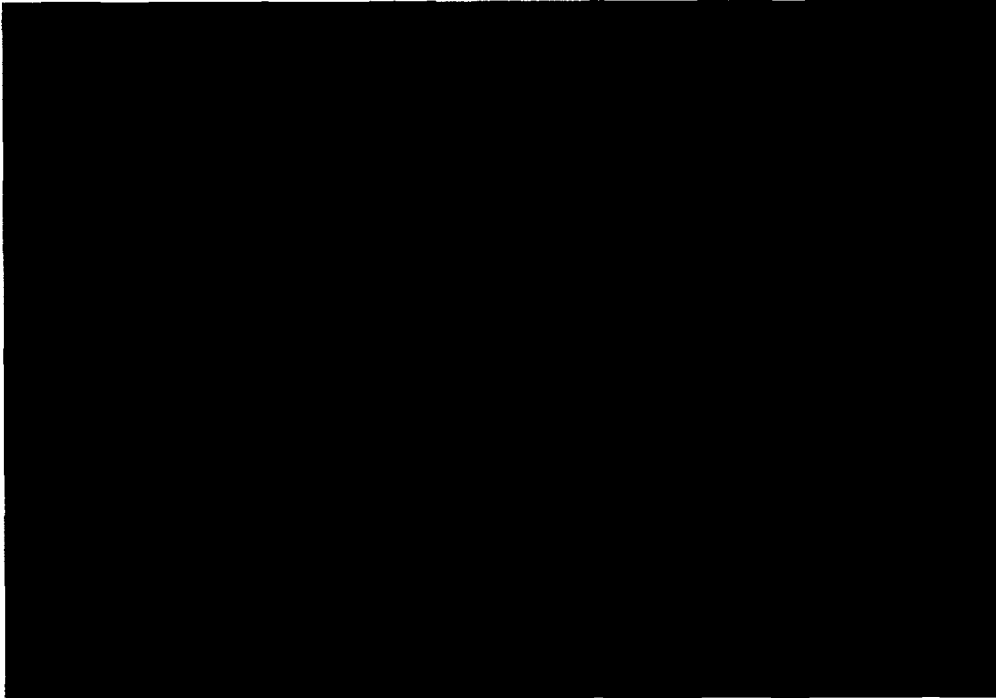


Figure 3. Percent change in projected gas price from 2010 forecast to forecast used in the present Docket, by year.

3 **Q. WHAT IS YOUR OVERALL CONCLUSION REGARDING APS'S**
4 **REVISIONS TO ITS FUEL PRICE FORECASTS, AS APPLIED TO**
5 **THIS DOCKET?**

6 **A.** My conclusion in this area is that the combination of two changes in fuel
7 price outlook, that is, higher-cost coal and lower-cost gas relative to that
8 anticipated in 2010, substantially reduces the value of the Four Corners
9 acquisition for APS ratepayers. In itself, this change may well have been
10 enough to eliminate any such benefit, even using APS's anomalous revised
11 forecasts which (as noted above) revert to the outdated 2010 forecasts after

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1 only a few years. Had the forecasts not exhibited this anomalous reversion,
2 the effect would have been much greater—and would have substantially
3 reduced, or more likely eliminated, the projected benefit of the acquisition
4 for ratepayers.

5 **Change in APS's Treatment of Future CO₂ Emissions Costs**

6 **Q. WHAT IS THE SIGNIFICANCE OF APS'S PROJECTIONS OF CO₂**
7 **EMISSIONS COSTS AS IT APPLIES TO THE FOUR CORNERS**
8 **ACQUISITION, AND TO THIS DOCKET?**

9 **A.** CO₂ costs are a fundamental driver of the economics of resource options in
10 the electric sector, and APS has acknowledged this fact and has included
11 these costs in all of the analyses considered here. However, the company has
12 lacked clarity and detail in justifying its cost projections, and has made
13 significant and impactful changes in its approach with no explanation that I
14 have been able to discover. It is true that these costs are shrouded in
15 regulatory uncertainty as to their magnitude, form, and jurisdictional source.
16 This is all the more reason APS and other utilities and resource planners
17 should shine the full light of day on their approach, so that their assumptions
18 and conclusions can be fully understood and evaluated.

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1 **Q. HAVE YOU REVIEWED THE CARBON EMISSIONS PRICE**
2 **FORECASTS USED BY APS IN DOCKET NO. E-01345A-10-0474**
3 **(2010) AND IN THE CURRENT DOCKET?**

4 A. Yes. Assumed carbon emissions prices for the current filing were provided in
5 response to Commission Staff Data Request 35.35 (Exhibit EDH-5), and for
6 the 2010 docket in response to Sierra Club Data Request 2.4(b) (Exhibit
7 EDH-4).

8 **Q. HAS APS PROVIDED A SOURCE FOR ITS CARBON EMISSIONS**
9 **COST PROJECTIONS?**

10 A. The company has provided very little explanation for its emissions price
11 forecasts, particularly in the present docket. However, APS did provide a
12 study performed for the company by Charles River Associates as Appendix
13 A to its 2012 Integrated Resource Plan.¹⁷ This study, which I have attached
14 as Exhibit EDH-6, recommends for the base case "...using \$12 (2011\$) per
15 metric tonne CO₂ Eq beginning in 2018-2020 and rising at 5% above inflation."
16 (2012 IRP Appendix A, p. A-11) For the high case, CRA argues that "it
17 makes sense to evaluate a higher carbon price trajectory, for example \$20
18 (2011\$) per metric tonne of CO₂ Eq beginning in 2018-2020 and rising at 5%
19 above inflation." They go on to note that they "do not believe that this is the

¹⁷ Charles River Associates, Arizona Public Service Greenhouse Gas Legislative Review and CO₂ Price Outlook." (Exhibit EDH-6) Dated November 4, 2011.

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1 highest carbon price trajectory that is politically feasible, but it represents an
2 upper bound to reflect probable policy over the next decade.”

3 The price trajectories provided by APS in response to Sierra Club data
4 requests, along with my interpretation of those recommended by CRA, are
5 shown in Figure 4.

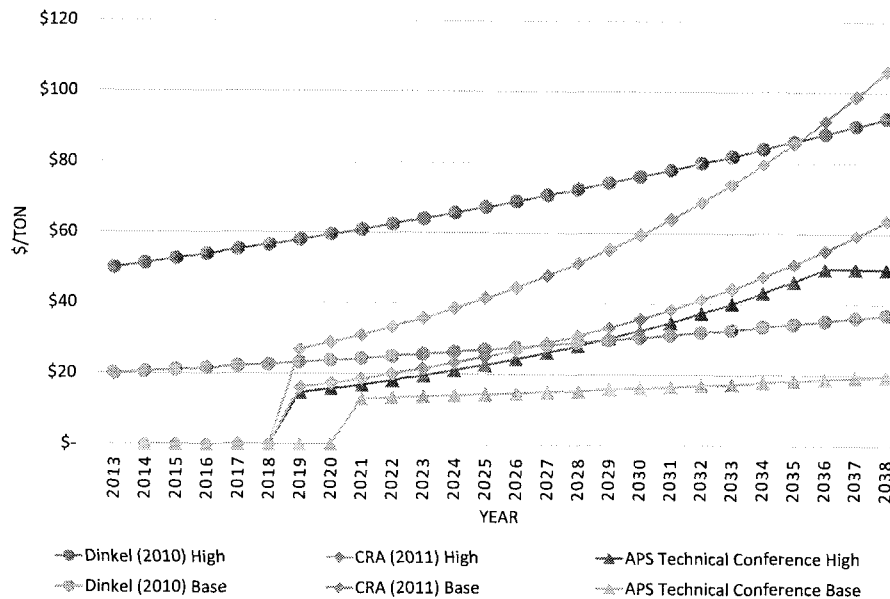


Figure 4. Comparison of all base and high case CO₂ emissions price trajectories used by APS and recommended by CRA, 2011-2014 (nominal dollars).

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1 **Q. HOW DO THE CO₂ PRICE FORECASTS USED IN THE CURRENT**
2 **DOCKET COMPARE TO THOSE RECOMMENDED BY CRA IN**
3 **2011?**

4 A. APS diverged quite dramatically from the recommendations of its consultant.
5 First, it appears that APS made a simple unit conversion error – by taking
6 CRA’s prices, which are denominated in dollars per metric tonne, and
7 applying them as if they were dollars per short ton. This in itself renders the
8 effective prices about 10% below what CRA intended.

9 Second, APS appears to have taken CRA’s “Base Case”, improperly applied
10 as dollars per short ton, and used it as a “High Case.” APS’s “Base Case” is
11 substantially lower, and the company has provided no explanation for this
12 case. APS has not considered CRA’s recommended “High Case” in the
13 current docket.

14 **Q. HOW DO THE CO₂ PRICE FORECASTS USED IN THE CURRENT**
15 **DOCKET COMPARE TO THOSE USED BY THE COMPANY IN**
16 **SUPPORT OF ITS 2010 FILING?**

17 A. As seen in Figure 4, the forecasts used in the current case are far below those
18 used by APS witness Patrick Dinkel in the 2010 docket. It appears that the
19 company’s current “High Case” is similar to Mr. Dinkel’s “Base Case,” but
20 Mr. Dinkel’s “High Case” has been dropped from consideration.

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**Q. HOW DO THE CARBON PRICE FORECASTS USED BY APS IN
THE CURRENT PROCEEDING COMPARE TO THOSE
RECOMMENDED BY CRA, AND TO OTHER CO₂ EMISSIONS
PRICES USED BY THE COMPANY, ON A LEVELIZED BASIS?**

A. Levelized prices are a useful single-number metric because they allow for apples-to-apples comparison amongst different trajectories that start in different years and grow at different rates. For the current case, I determined equivalent levelized prices for each trajectory by first applying the “NPV” function in Excel with a 7.2% discount rate to each trajectory over the period 2019-2038. I then used the “PMT” function in Excel to find an equivalent stream of constant annual payments from 2012-2038 that would yield the same NPV – or the equivalent levelized price over this time period. Table 3 compares the levelized prices for each of the trajectories shown in Figure 4.

Table 3. Comparison of APS' CO₂ price trajectories on a levelized basis

Source	Levelized CO ₂ Price 2019-2038
Base Case	
Current Docket	\$12.73
Dinkel (2010)	\$28.01
CRA 2011	\$29.60
High Case	
Current Docket	\$26.58
Dinkel (2010) High	\$70.02
CRA 2011 High	\$49.34

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1 As seen in Table 3, the "Base Case" price used by APS in its technical
2 conference presentation, and used to support the current application, is well
3 below the other price trajectories shown on a levelized basis. It is less than
4 half of either the Base Case price used by Mr. Dinkel in 2010, or the Base
5 Case price recommended by APS's consultant CRA. In fact, even APS's
6 technical conference "High Case" price is below either the CRA or the
7 Dinkel "Base Case" prices, on a levelized basis.

8 **Q. BASED ON THE FOREGOING, DO YOU BELIEVE THAT THE**
9 **COMPANY'S REVISIONS TO ITS CARBON EMISSIONS PRICE**
10 **FORECASTS WERE REASONABLE?**

11 A. No. I conclude that the company erred in choosing both base and high case
12 trajectories that are too low, and that ignore the guidance of its own
13 consultants in this area. The company's emissions prices used to support its
14 "fair value" petition for Four Corners are below both the 2012 and 2014 IRP
15 trajectories; it is hard to reconcile this observation with any realistic or
16 credible change in APS's market outlook during this period.

17 **Q. WHAT IS THE IMPACT OF THIS APPROACH ON THE**
18 **COMPANY'S ANALYSIS?**

19 A. The impact is quite significant. In response to Sierra Club data request No.
20 2.4(a) (Exhibit EDH-4), APS provided its projected total CO₂ emissions costs
21 under each of the scenarios considered and presented at the February 2014

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1 Technical Conference. The CO₂ emissions costs alone have an NPV of \$1.75
2 Billion (2010-2039) for the Four Corners acquisition plan, and \$1.19 Billion
3 for the alternative plan—an additional NPV cost of \$560 Million for the
4 acquisition case relative to the alternative. This suggests that if the Base Case
5 emissions prices were twice as high (which would still be lower than either
6 the CRA Base Case or the Dinkel Base Case emissions prices) there would
7 have been an *additional* \$560 Million NPV penalty for the acquisition case—
8 well exceeding the \$426 Million net benefit to ratepayers claimed by the
9 company.

10 As with the fuel costs, my quantitative estimate of the impact assumes no
11 change in dispatch – but again as with fuel costs, it strongly suggests that the
12 impact is important, and that were the company more thorough and
13 forthcoming in its analysis, it would be presenting a very different picture of
14 the relative benefits of the acquisition.

15 **Q. WHAT IS YOUR OVERALL CONCLUSION REGARDING APS'S**
16 **REVISIONS TO ITS CO₂ EMISSIONS COST FORECASTS, AS**
17 **APPLIED TO THIS DOCKET?**

18 **A.** I conclude that a very significant and unexplained change was made in the
19 company's stated carbon emissions price outlook – a change that is
20 inconsistent not only with the company's earlier practice, but with its
21 consultant's recommendations. This change has enough of an impact on the

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1 company's NPV analysis to reverse the result – that is, without this change
2 the company would find that the alternative plan, relying on new natural gas
3 plants, would be less costly on an NPV basis than the Four Corners
4 acquisition.

5 The Commission should require a much more complete, detailed, and
6 rigorous explanation of the company's change in its carbon price forecast
7 prior to ruling on the current petition; further, the company should be
8 required to re-run its analysis using the CO₂ emissions prices recommended
9 by its consultant CRA. If ratepayer benefits cannot be shown using realistic
10 and fully justified CO₂ emissions prices, the petition should be denied.

11 **Change in Projected Capital Expenditures for Units 4 and 5**

12 **Q. HAVE YOU REVIEWED APS'S PROJECTED CAPITAL**
13 **EXPENDITURES ON ITS GENERATING UNITS, INCLUDING**
14 **FOUR CORNERS, AS APPLIED IN DOCKET E-01345A-10-0474 AND**
15 **IN THE CURRENT DOCKET?**

16 **A.** Yes. APS provided projected annual capital expenditures as applied for the
17 current filing in response to Sierra Club Data Request 2.4(a), and for the
18 2010 docket in response to Sierra Club Data Request 2.4(d), both of which
19 are included in Exhibit EDH-4. The capital costs were provided for the
20 following categories: APS's share of Four Corners 4 and 5, Future CCs/CTs,

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1 and "Other Existing."¹⁸ The company has alleged that much of this
2 information is confidential.

3 **Q. HOW DID APS'S PROJECTIONS OF CAPITAL EXPENDITURES**
4 **CHANGE BETWEEN ITS FILING IN 2010 AND THE CURRENT**
5 **DOCKET?**

6 A. There were quite a number of changes, and they are difficult to reconcile
7 given the limited information or explanation the company has provided.
8 CONFIDENTIAL Table 4 summarizes the changes in projected capital
9 expenditures by resource category, on an NPV basis,¹⁹ between the 2010
10 filing and the current docket. Values are shown for both the "Base Case,"
11 which represents the acquisition of SCE's share of Four Corners, and the
12 "Gas Alternative," in which Four Corners is shut down in 2016 and APS's
13 resource needs are met by building new gas plants.²⁰

14 In the "Gas Alternative" case, the company's projection of capital costs for
15 APS's share of Four Corners until shutdown increased by [REDACTED] relative to its

¹⁸ The current data also break out Four Corners Units 1-3, but these expenditures are small and disappear entirely by 2016. For purposes of the discussion here these are included in "Other Existing."

¹⁹ The values in CONFIDENTIAL Table 4 represent Net Present Value for the years 2014-2039, using a discount rate of 7.2%. The underlying data are deemed confidential by the company.

²⁰ The cases shown were defined and analyzed by APS, and were included in the filing and discovery materials provided by the company. I do not know the details of the two alternative resource plans, nor can I be completely confident that the alternatives considered in the two cases were identical.

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1 2010 projection. Conversely, the projected capital expenditures associated
2 with the same plant in the Base Case *decreased* by almost [REDACTED]. This
3 combination of a projected Four Corners capital cost decrease in the Base
4 Case and a projected increase in the Gas Alternative case accounts for \$185
5 Million of the NPV difference between the cases – about 43% of the entire
6 claimed benefit for the Base Case over the alternative.

7 The decrease in the projected capital cost relative to the 2010 filing has
8 another perplexing aspect: Between 2010 and 2014, the company's
9 expectation for capital costs for all of its existing resources—except Four
10 Corners Units 4 and 5 – *increased* by [REDACTED]. If the company had expected the
11 capital expenditures associated with Four Corners to increase by [REDACTED] along
12 with the rest of the fleet, the NPV benefit of the Base Case would be reduced
13 by \$473 Million – more than eliminating the entire claimed benefit. The
14 company should be required to explain why it believes Four Corners costs
15 will remain low while other resources in its portfolio have become more
16 expensive to maintain.

17 The source of the reduction in NPV capital costs for the Four Corners units is
18 also intriguing. CONFIDENTIAL Figure 5 shows the annual capital
19 expenditures as projected by APS in support of each filing. The undiscounted
20 sum of the capital expenditures projected in 2014, shown in the final set of
21 rows in CONFIDENTIAL Table 4, is actually about [REDACTED] greater

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1 than the undiscounted sum of those projected in 2010; however, by
2 projecting a delay in these expenditures of several years, APS has realized a
3 decrease in the calculated NPV through the mechanics of discounting.
4

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CONFIDENTIAL Table 4: Changes in projected capital expenditures from APS's filing in Docket No. E-01345A-10-0474 to the current case, by resource category and case. Values are in \$Million NPV for the years 2014-2039, using a discount rate of 7.2%

		Gas	
		Base Case	Alternative
Four Corners 4-5	2010	████████	████████
	2014	████████	████████
	Change (\$M)	████████	████████
	Change (%)	████████	████████
Other Existing	2010	████████	████████
	2014	████████	████████
	Change (\$M)	████████	████████
	Change (%)	████████	████████
Future CCs/CTs	2010	████████	████████
	2014	████████	████████
	Change (\$M)	████████	████████
	Change (%)	████████	████████
Four Corners 4-5 (Un- discounted)	2010	████████	████████
	2014	████████	████████
	Change (\$M)	████████	████████
	Change (%)	████████	████████

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CONFIDENTIAL Figure 5. Annual capital expenditures for the Four Corners plant as projected by APS in 2010 (blue) and the current docket (Orange)

1
2 **Q. WHAT IS YOUR OVERALL CONCLUSION REGARDING APS'S**
3 **TREATMENT OF FUTURE CAPITAL COSTS IN THIS CASE?**

4 A. I find that there were numerous anomalous and unexplained changes to the
5 capital cost projections between the 2010 filing and the current docket, all of
6 which tend to favor the acquisition of Four Corners over the gas alternative.
7 The aggregate impact of these changes, on an NPV basis, exceeds the NPV
8 benefit the company has shown for its preferred plan.

9 The Commission should require a much more complete explanation of the
10 company's changes in its capital cost projections prior to ruling on the

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1 current petition; if these changes are not fully justified, the petition should be
2 denied.

3 **Other Assumptions and Considerations**

4 **Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING APS'S**
5 **ASSUMPTIONS AND ECONOMIC ANALYSIS IN THIS CASE?**

6 A. Yes. In particular, I would like to reiterate a concern raised by Sierra Club
7 witness David Schlissel in Docket No. E-01345A-10-0474 before this
8 Commission. Specifically, I note that APS's analysis is still fully dependent
9 on the assumption that the Four Corners units will continue to operate, and to
10 operate at a high capacity factor, through 2039, when the units will be 70
11 years old.

12 **Q. DO YOU HAVE REASON TO BELIEVE THAT THE UNITS WILL**
13 **CEASE OPERATING, OR WILL OPERATE AT A LOWER LEVEL,**
14 **PRIOR TO 2039?**

15 A. I do not know how the units will operate into their seventh decade of service,
16 and neither does APS. It is certainly reasonable to assume that, like all capital
17 equipment, they will require increasing infusions of capital as they age if
18 they are to continue running at such a high level—but APS has actually
19 assumed that capital costs will be close to constant in nominal dollars,
20 meaning that they would decrease precipitously in real terms.
21 (CONFIDENTIAL Figure 5). In fact, as the units age and if these costs

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1 increase, APS and the other co-owners may well decide to retire one or both
2 units early, or to allow them to run at a much lower level, rather than to
3 continue investing in aging infrastructure. Thus I believe it is an extremely
4 optimistic assumption that they will continue to run at high capacity factors
5 throughout this period.

6 Further, the risks and costs associated with burning fossils fuels and
7 continuing to emit large quantities of greenhouse gases into the atmosphere
8 are becoming clearer seemingly every day. As I write this testimony, the
9 Intergovernmental Panel on Climate Change is completing its fifth
10 Assessment Report on global climate change,²¹ and the results are alarming.
11 The draft report leaves no doubt that climate change is occurring, and that
12 human activity—specifically the continued release of greenhouse gases into
13 the atmosphere—is the major cause.

14 On May 6 of this year, the Obama Administration released the Third US
15 National Climate Assessment.²² Among the conclusions of that report are
16 that climate change is already causing costly and disruptive impacts in the
17 United States and elsewhere on air quality, infrastructure, water supply,

²¹ <http://www.ipcc.ch/report/ar5/index.shtml>

²² Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: Highlights of Climate Change Impacts in the United States: The Third National Climate Assessment. U.S. Global Change Research Program, 148 pp.

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1 agriculture, the way of life of indigenous people, ecosystems, marine life,
2 and human health. These impacts are only expected to become more severe
3 and costly in the years and decades to come.

4 Finally, on June 2, 2014 the US EPA released its plans for regulating carbon
5 emissions from existing power plants, calling for a reduction of 30% from
6 2005 levels by 2030. While the implementation details and the impact of this
7 rule are still being worked out, one thing is clear: there are going to be large
8 and increasing costs associated with continuing to run resources, such as
9 Four Corners Units 4 and 5, that emit large amounts of CO₂ into the
10 atmosphere.

11 While APS has made its first steps towards incorporating risk of climate
12 legislation and emissions costs into account by including a modest cost for
13 CO₂ emissions, the company should recognize that if the United States is to
14 seriously address this critical risk to our economy and the climate of the
15 planet, it will likely become uneconomic to run coal plants at a high level, or
16 perhaps at all, in the coming decades. Prior to asking this Commission to
17 approve ratepayer funding for acquiring additional coal-burning
18 infrastructure today, the company should at least identify what the
19 implications would be for their analysis if the plant were unable or
20 uneconomic to operate and to continue producing greenhouse gas emissions
21 at some point prior to the end of its projected lifetime.

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1 **Q. WHAT WOULD BE THE IMPACT ON THE COMPANY'S**
2 **ANALYSIS IF IT RAN A SENSITIVITY CASE WITH AN EARLIER**
3 **SHUTDOWN DATE?**

4 A. It is difficult to know what the financial impact would be without producing
5 a full resource plan assuming an earlier shutdown date—something that
6 would be straightforward for APS to do but unduly burdensome for an
7 outside expert without full access to APS's planning models. As presented by
8 APS, and with all of the input assumption issues described herein, the Four
9 Corners option overtakes the gas alternative option on an NPV basis by
10 around 2022.

11 Of course, this should not be taken to imply that the Four Corners
12 Acquisition plan is preferable as long as operations continue through that
13 period, even given all of the questionable assumptions described above. In
14 the event Four Corners were to curtail operations or shut down early, APS
15 would still have to find or build alternative resources, such as those identified
16 in the gas alternative case, much earlier than anticipated in the Base Case
17 plan.

18 **Q. HAS APS PERFORMED SUCH AN ANALYSIS?**

19 A. Not that I am aware of. Indeed, Sierra Club asked for any such analysis in
20 Sierra Club interrogatory 3.1, and was informed that "In conjunction with the

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1 acquisition of SCE's share of Four Corners 4 and 5, APS did not evaluate
2 having an earlier shutdown of Four Corners 4 and 5.”²³

3 **Q. ARE THERE ANY OTHER RISKS THAT THE COMPANY HAS**
4 **FAILED TO CONSIDER IN ITS NPV ANALYSIS PRESENTED TO**
5 **THIS COMMISSION?**

6 **A.** Yes. For example, there is a significant risk that other environmental
7 remediation costs, such as the cost of installing SCRs to comply with the
8 Regional Haze Rule, will be significantly higher than the company has
9 estimated. While I am not a pollution control engineer and I cannot speak to
10 the specific issues related to the Four Corners units, my understanding is that
11 each such installation is highly site-specific, and that it is not uncommon for
12 installation costs to far exceed initial estimates. APS should address this risk
13 in its analysis, making a good-faith estimate of the upper bound on the cost
14 of such an installation, and analyze and report the impacts of such a case on
15 the economics of the resources. A good way to ensure a realistic, good-faith
16 upper bound estimate is for the company to stipulate that it will not seek to
17 recover costs in excess of that amount from ratepayers.

18 Similarly, there is a risk that the ultimate decommissioning and remediation
19 costs will be higher than the company estimates. This is particularly germane

²³ APS response to Sierra Club data request 3.1.

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1 as the company is taking on a much larger share of this risk through the
2 acquisition of SCE's share of the Four Corners units. Similar to the
3 environmental retrofit risk, I recommend that the company be directed to
4 analyze and report the impact of such a scenario on project economics, again
5 basing the analysis on a cost higher than which it will guarantee not to seek
6 recovery from ratepayers.

7 Of course, I do not know precisely what these costs will be any better than
8 the company does, but given the dubious, possibly biased, and poorly-
9 documented nature of other assumptions underlying the company's NPV
10 analysis, it is certainly possible that APS has underestimated and/or
11 understated the risks of higher costs. Even if the Commission is prepared to
12 award APS its requested rate increase based on the analysis presented by the
13 company, the company should not be given a blank check to cover future
14 costs that should have been anticipated and given full consideration in this
15 docket.

16 **IV. Overall Recommendations and Conclusions**

17 **Q. WHAT ARE YOUR RECOMMENDATIONS FOR THE**
18 **COMMISSION IN THIS CASE?**

19 **A.** First, I recommend that the Commission deny APS's petition at this time, and
20 direct the company to re-file its request with a revised analysis that is more

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1 detailed, and that provides a full explanation and justification for the
2 numerous changes in the company's assumptions and projections since the
3 2010 filing. It may be that the sum total of these many changes do indeed
4 cancel out, and that the surprising similarity between the currently-projected
5 \$426 Million Net Present Value benefit and the \$488 Million NPV benefit
6 projected in 2010 is merely a coincidence. However, there are far too many
7 anomalous and unexplained features of the company's numbers to accept this
8 conclusion without far more explanation.

9 In particular, I recommend that the Commission ask for fully detailed
10 explanations of the following:

- 11 • **Gas price forecasts.** Why is it that the company's gas price forecasts
12 revert to almost the same values as the 2010 forecasts between 2018
13 and 2024? Has APS fully incorporated the changed natural gas
14 market fundamentals in this assumption?
- 15 • **Greenhouse gas emissions costs.** Can the company explain how it
16 derived its revised greenhouse gas emissions costs, why it elected to
17 use the "Base Case" recommended by its consultant as "High Case",
18 and how its "Base Case" was derived? Assuming APS did rely at
19 least in part on CRA's recommendations, the company should also
20 correct its error in units identified above, if my interpretation is
21 correct.
- 22 • **Capital expenditures.** Can the company explain why it changed its
23 projected stream of capital expenditures for Four Corners since the
24 2010 filing as described above, why the expected capital expenditures
25 decreased in the Base Case while increasing dramatically in the
26 Alternative Case, and why the projected expenditures for Four
27 Corners remained almost constant (in nominal dollars) while they
28 increased markedly for all other resources?

REDACTED

- 1 • **Long-term unit operations.** Has the company considered a case
2 where the plant does *not* operate at a high capacity factor through the
3 end of 2039? If so, what are the implications of such an early shut-
4 down (or curtailed operations) for the economics of the acquisition? If
5 not, does the company intend to hold ratepayers harmless if this
6 assumption turns out to be unrealistically optimistic for the readily
7 foreseeable reasons unidentified here?
- 8 • **Other costs.** Has APS considered a case in which other costs, such as
9 environmental retrofit, remediation, and decommissioning costs, are
10 higher than the company has projected in its base case analysis?

11 Without much more detailed explanation and justification of the company's
12 assumptions and analytical decisions in each of these areas, I do not believe
13 that the Commission can reasonably accept APS's NPV analysis as valid or
14 robust, nor can it approve the company's request in this docket.

15 Second, I recommend that the Commission put APS on notice that there is no
16 guarantee of recovery of future capital investments in the Four Corners plant.
17 The Commission waived the self-build moratorium in Order No. 73130—but
18 it did not relieve the company of the burden of making and justifying prudent
19 decisions. Had APS performed its revised analysis with the CO₂ price
20 trajectories recommended by its own consultant, or made numerous other
21 reasonable changes to its underlying assumptions described here, it would
22 have found no or even negative benefit from the Four Corners acquisition on
23 an NPV basis; if it turns out that other assumptions were also unrealistically
24 biased in favor of the acquisition, the company should be held accountable.
25 Such assumptions could include the future operations and longevity of the

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1 plant; the extent and cost of required environmental upgrades, and
2 decommissioning and remediation costs.

3 Similarly, while the company has not at this time requested ratemaking
4 treatment for the acquisition of El Paso Electric's 7% share of Four Corners
5 Units 4 and 5, I recommend that the Commission put the company on notice
6 that a fully updated analysis will be required before ratepayers are shouldered
7 with this additional risk and cost. Continued investment in Four Corners on
8 behalf of APS's ratepayers risks becoming a game of throwing good money
9 after bad, as each "investment" becomes a sunk cost that justifies the next. It
10 was APS's analysis and decisions that started this process, however, and the
11 company, not its ratepayers, should bear the risk of any imprudence or sub-
12 par analysis in the process.

13 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

14 **A.** Yes.
15

Exhibit EDH-1

Resume of Ezra D. Hausman, PH.D.

Ezra Daskal Hausman, Ph.D.

77 Kaposia Street
Newton, Massachusetts 02466
(617) 875-6698
www.ezrahausman.com
ezra@ezrahausman.com

SUMMARY

I am an independent consultant in energy and environmental economics.

I have worked for over 15 years as an electricity market expert with a focus on market design and market restructuring, environmental regulation in electricity markets, and pricing of energy, capacity, transmission, losses and other electricity-related services. I have performed market analysis, offered expert testimony, led workshops and working groups, made presentations and participated on panels, and provided other support to clients in a number of areas, including:

- Economic analysis, price forecasting, and asset valuation in electricity markets, including dispatch model analysis and review of modeling studies
- Electricity and generating capacity market design
- Integrated Resource Planning and portfolio analysis
- Economic analysis of environmental and other regulations, including cap-and-trade regulation of CO₂, in electricity markets
- Quantification of the economic and environmental benefits of displaced emissions associated with energy efficiency and renewable energy initiatives
- Mitigation of greenhouse gas emissions from the supply and demand sides of the U.S. electric sector.

I have prepared reports and offered other expert services on these and other related topics for clients including federal and state agencies; offices of consumer advocate; legislative bodies; cities and towns; non-governmental organizations; foundations; industry associations; and resource developers.

I previously served as Vice President and Chief Operating Officer of Synapse Energy Economics, Inc. of Cambridge, Massachusetts. In addition to my consulting portfolio, this management role entailed responsibility for day-to-day operations of the company including overseeing finance, HR, communications & marketing, quality assurance, client service, and professional development of staff. I had overall responsibility for ensuring that project managers and project teams had the tools, information, and training they needed to successfully serve our client's needs and produce high-quality deliverables on time and on budget. I was also a resource available to any of our clients to address any issues of customer service, quality, or any other issues that may arise.

I hold a Ph.D. in atmospheric science from Harvard University, an S.M. in applied physics from Harvard University, an M.S. in water resource engineering from Tufts University, and a B.A. degree in psychology from Wesleyan University.

PROFESSIONAL EXPERIENCE

Ezra Hausman Consulting, Newton, MA. President, March 2014 – Present.

I provide research, analytical, and regulatory and litigation support services based upon my 15+ years experience in the electric power industry.

Synapse Energy Economics Inc., Cambridge, MA.

Chief Operating Officer, March 2011 – February 2014;

Vice President, July 2009 – February 2014;

Senior Associate, 2005-2009.

Conducted research, wrote reports, and presented expert testimony pertaining to consumer, environmental, and public policy implications of electricity industry regulation. Focus of work included:

- Economic analysis of electricity industry regulation and restructuring
- Efficient pricing of generating and transmission capacity
- Long-term electric power system planning and market design
- Price forecasting and asset valuation
- Impact of air quality and environmental regulations on electricity markets and pricing
- Energy efficiency and renewable energy programs and policies, including avoided emissions analysis
- Market power and market concentration analysis in electricity markets
- Consumer and environmental protection
- Regulation and mitigation of greenhouse gas emissions.

Charles River Associates (CRA), Cambridge, MA. Senior Associate, 2004-2005

CRA acquired Tabors Caramanis & Associates in October, 2004.

Tabors Caramanis & Associates, Cambridge, MA. Senior Associate, 1998-2004

Modeling and analysis of electricity markets, generation and transmission systems. Projects included:

- Several market transition cost-benefit studies for development of Locational Marginal Price (LMP) based markets in US electricity markets
- Long-term market forecasting studies for valuation of generation and transmission assets,
- Valuation of financial instruments relating to transmission system congestion and losses
- Modeling and analysis of hydrologically and electrically interconnected hydropower system operations
- Natural gas market analysis and price forecasting studies
- Co-developed an innovative approach to hedging financial risk associated with transmission system losses of electricity

- Designed, developed and ran training seminars using a computer-based electricity market simulation game, to help familiarize market participants and students in the operation of LMP-based electricity markets.
- Developed and implemented analytical tools for assessment of market concentration in interconnected electricity markets, based on the “delivered price test” for assessing market accessibility in such a network
- Performed regional market power and market power mitigation studies
- Performed transmission feasibility studies for proposed new generation and transmission projects in various locations in the US
- Provided analytical support for expert testimony in a variety of regulatory and litigation proceedings, including breach of contract, bankruptcy, and antitrust cases, among others.

Global Risk Prediction Network, Inc., Greenland, NH. Vice President, 1997-1998

Developed private sector applications of climate forecast science in partnership with researchers at Columbia University. Specific projects included a statistical assessment of grain yield predictability in several crop regions around the world based on global climate indicators (Principal Investigator); a statistical assessment of road salt demand predictability in the United States based on global climate indicators (Principal Investigator); a preliminary design of a climate and climate forecast information website tailored to the interests of the business community; and the development of client base.

Hub Data, Inc., Cambridge, MA. Financial Software Consultant, 1986-1987, 1993-1997

Responsible for design, implementation and support of analytic and communications modules for bond portfolio management software; and developed software tools such as dynamic data compression technique to facilitate product delivery, Windows interface for securities data products.

Abt Associates, Inc., Cambridge, MA. Environmental Policy Analyst, 1990-1991

Quantitative risk analysis to support federal environmental policy-making. Specific areas of research included risk assessment for federal regulations concerning sewage sludge disposal and pesticide use; statistical alternatives to Most-Exposed-Individual risk assessment paradigm; and research on non-point sources of water pollution.

Massachusetts Water Resources Authority, Charlestown, MA. Analyst, 1988-1990

Applied and evaluated demand forecasting techniques for the Eastern Massachusetts service area. Assessed applicability of various techniques to the system and to regional planning needs; and assessed yield/reliability relationship for the eastern Massachusetts water supply system, based on Monte-Carlo analysis of historical hydrology.

Somerville High School, Somerville, MA. Math Teacher, 1986-1987

Courses included trigonometry, computer programming, and basic math courses.

EDUCATION

Ph.D., Earth and Planetary Sciences. Harvard University, Cambridge, MA, 1997

S.M., Applied Physics. Harvard University, Cambridge, MA, 1993

M.S., Civil Engineering. Tufts University, Medford, MA, 1990

B.A., Wesleyan University, Psychology. Middletown, CT, 1985

FELLOWSHIPS, AWARDS AND AFFILIATIONS

President, Burr Elementary School Parent Teacher Organization, 2005-2007

UCAR Visiting Scientist Postdoctoral Fellowship, 1997

Postdoctoral Research Fellowship, Harvard University, 1997

Certificate of Distinction in Teaching, Harvard University, 1997

Graduate Research Fellowship, Harvard University, 1991-1997

Invited Participant, UCAR Global Change Institute, 1993

House Tutor, Leverett House, Harvard University, 1991-1993

Graduate Research Fellowship, Massachusetts Water Resources Authority, 1989-1990

Teaching Fellowships:

Harvard University: *Principles of Measurement and Modeling in Atmospheric Chemistry; Hydrology; Introduction to Environmental Science and Public Policy; The Atmosphere.*

Wesleyan University: *Introduction to Computer Programming; Psychological Statistics; Playwriting and Production.*

Professional affiliations

Member, American Association for the Advancement of Science

Member, American Economic Association

EXPERT TESTIMONY AND SERVICES

United States District Court for the Eastern District of Missouri (Civil Action No. 4:11-CV-00077) – Ongoing

Expert witness on behalf of the United States Department of Justice on clean air act enforcement case.

Arizona Corporation Commission (Docket No. E-01345A-11-0224) – Ongoing

Expert witness on behalf of the Sierra Club regarding Arizona Public Service petition for rate treatment for acquisition of an additional ownership share of the Four Corners generating units.

Missouri Public Service Commission (Docket No. ET-2014-0085) – 2013

Testimony on behalf of the Missouri Solar Energy Industries Association regarding Union Electric (d/b/a Ameren Missouri) motion to suspend payment of solar rebates.

Missouri Public Service Commission (Docket No. ET-2014-0059 and ET-2014-0071) – 2013

Testimony on behalf of the Missouri Solar Energy Industries Association regarding Kansas City Power and Light Company's motions to suspend payment of solar rebates.

Puget Sound Energy (PSE) – 2012-2013

Expert participant in PSE's 2013 IRP stakeholder process on behalf of the Sierra Club.

Washington Utilities and Transportation Commission (Docket Nos. UE-111048 and UG-111049) – 2011

Testimony on behalf of the Sierra Club regarding the cost of operating the Colstrip power plant and other power procurement issues.

Kansas Corporation Commission (Docket No. 11-KCPE-581-PRE) - 2011

Presented written and live testimony on behalf of the Sierra Club regarding Kansas City Power and Light request for predetermination of ratemaking principles.

Vermont Department of Public Service - 2011

Provided scenario analysis of the costs and benefits of various electric energy resource scenarios in support of the state Comprehensive Energy Plan.

Massachusetts Department of Energy Resources – 2009-2011

Served as expert analyst and modeling coordinator for analysis related to implementation of the Massachusetts Global Warming Solutions Act.

Iowa Office of Consumer Advocate – 2010-Present

Assisted Consumer Advocate in evaluating a proposed power purchase agreement for the output of the Duane Arnold nuclear power station.

Missouri Public Service Commission (Docket No. EW-2010-0187) – 2010

Expert participant on behalf of the Sierra Club in stakeholder process to develop a "demand side investment mechanism" in Missouri.

Louisiana Public Service Commission (Docket No. R-28271 Subdocket B) – 2009-2010

Expert participant on behalf of the Sierra Club in Renewable Portfolio Standard Task Force considering RPS for Louisiana.

Joint Fiscal Committee of the Vermont Legislature – 2008-2010

Serving as lead expert advising the Legislature on economic issues related to the possible recertification of the Vermont Yankee nuclear power plant.

Town of Littleton, NH – 2006-2010

Serving as expert witness on the value of the Moore hydroelectric facility.

Nevada Public Service Commission (Docket No. 08-05014) – August 2008

Presented prefiled and live testimony on behalf of Nevadans for Clean Affordable Reliable Energy regarding the proposed Ely Energy Center and resource planning practices in Nevada.

Mississippi Public Service Commission (Docket No. 2008-AD-158) – August 2008

Presented written and live testimony on behalf of the Sierra Club regarding the resource plans filed by Entergy Mississippi and Mississippi Power Company.

Kansas House of Representatives - Committee on Energy and Utilities – February 2008

Presented testimony on behalf of the Climate and Energy Project of the Land Institute of Kansas on a proposed bill regarding permitting of power plants. Focus was on the risks and costs associated with new coal plants and on their contribute to global climate change.

Vermont Public Service Board (Docket No. 7250) – 2006-2008

Prepared report and testimony in support of the application of Deerfield Wind, LLC. For a Certificate of Public Good for a proposed wind power facility.

Iowa Utilities Board (Docket No. GCU-07-1) – October, 2007 – January 2008

Presented wrtten and live testimony on behalf of the Iowa Office of Consumer Advocate regarding the science of global climate change and the contribution of new coal plants to atmospheric CO₂.

Nevada Public Service Commission (Docket No. 07-06049) – October 2007

Presented prefiled direct testimony on behalf of Nevadans for Clean Affordable Reliable Energy regarding treatment of carbon emissions costs and coal plant capital costs in utility resource planning.

Massachusetts General Court, Joint Committee on Economic Development and Emerging Technologies – July 2007

Presented written and live testimony on climate change science and the potential benefits of a revenue-neutral carbon tax in Massachusetts.

Town of Rockingham, VT – 2006-2007

Served as expert witness on the value of the Bellows Falls hydroelectric facility.

South Dakota Public Utilities Commission (Case No EL05-22) – June 2006

Minnesota Public Utilities Commission (Docket TR-05-1275) – December 2006

Submitted prefiled and live testimony on the contribution of the proposed Big Stone II coal-fired generator to atmospheric CO₂, global climate change and the environment of South Dakota and Minnesota, respectively.

Arkansas Public Service Commission (Docket No. 06-070-U) – October 2006

Submitted prefiled direct testimony on inclusion of new wind and gas-fired generation resources in utility rate base.

Federal Energy Regulatory Commission (Docket Nos. ER055-1410-000 and EL05-148-000) – May-Sept 2006

- Participant in settlement hearings on proposed capacity market structure (the Reliability Pricing Model, or RPM) on behalf of State Consumer Advocates in Pennsylvania, Ohio and the District of Columbia

- Invited participant on technical conference panel on PJM's proposed Variable Resource Requirement (VRR) curve
- Filed Pre- and post-conference comments and affidavits with FERC
- Participated in numerous training and design conferences at PJM on RPM implementation.

Illinois Pollution Control Board (Docket No. R2006-025) – June-Aug 2006

Profile and live testimony presented on behalf of the Illinois EPA regarding the costs and benefits of proposed mercury emissions rule for Illinois power plants.

Long Island Sound LNG Task Force – January 2006

Presentation of study on the need for and alternatives to the proposed Broadwater LNG storage and regasification facility in Long Island Sound.

Iowa Utilities Board (Docket No. SPU-05-15) – November 2005

Whether Interstate Power and Light's should be permitted to sell the Duane Arnold Energy Center nuclear facility to FPLE Duane Arnold, Inc., a subsidiary of Florida Power and Light.

PUBLICATIONS AND REPORTS

Luckow, P., E. Stanton, B. Biewald, J. Fisher, F. Ackerman, E. Hausman, *2013 Carbon Dioxide Price Forecast*, Synapse Energy Economics, November 2013.

Stanton, E., T. Comings, K. Takahashi, P. Knight, T. Vitolo, E. Hausman, *Economic Impacts of the NRDC Carbon Standard: Background Report prepared for the Natural Resources Defense Council*, Synapse Energy Economics for NRDC, June 2013

Comings T., P. Knight, E. Hausman, *Midwest Generation's Illinois Coal Plants: Too Expensive to Compete? (Report Update)* Synapse Energy Economics for Sierra Club, April 2013

Stanton E., F. Ackerman, T. Comings, P. Knight, T. Vitolo, E. Hausman, *Will LNG Exports Benefit the United States Economy?* Synapse Energy Economics for Sierra Club, January 2013

Chang M., D. White, E. Hausman, *Risks to Ratepayers: An Examination of the Proposed William States Lee III Nuclear Generation Station, and the Implications of "Early Cost Recovery" Legislation*, Synapse Energy Economics for Consumers Against Rate Hikes, December 2012

Wilson R., P. Luckow, B. Biewald, F. Ackerman, and E.D. Hausman, *2012 Carbon Dioxide Price Forecast*, Synapse Energy Economics, October 2012.

Fagan B., M. Chang, P. Knight, M. Schultz, T. Comings, E.D. Hausman, and R. Wilson, *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region*. Synapse Energy Economics for Energy Future Coalition, May 2012.

Hausman, E.D., T. Comings, *"Midwest Generation's Illinois Coal Plants: Too Expensive to Compete?"* Synapse Energy Economics for Sierra Club, April 2012.

Hausman, E.D., T. Comings, and G. Keith, *Maximizing Benefits: Recommendations for Meeting Long-Term Demand for Standard Offer Service in Maryland*. Synapse Energy Economics for Sierra Club, January 2012.

Keith G., B. Biewald, E.D. Hausman, K. Takahashi, T. Vitolo, T. Comings, and P. Knight, *Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011* Synapse Energy Economics for Civil Society Institute, November 2011.

Chang M., D. White, E.D. Hausman, N. Hughes, and B. Biewald, *Big Risks, Better Alternatives: An Examination of Two Nuclear Energy Projects in the U.S.* Synapse Energy Economics for Union of Concerned Scientists, October 2011.

Hausman E.D., T. Comings, K. Takahashi, R. Wilson, and W. Steinhurst, *Electricity Scenario Analysis for the Vermont Comprehensive Energy Plan 2011*. Synapse Energy Economics for Vermont Department of Public Service, September 2011.

Wittenstein M., E.D. Hausman, *Incenting the Old, Preventing the New: Flaws in Capacity Market Design, and Recommendations for Improvement*. Synapse Energy Economics for American Public Power Association, June 2011.

Johnston L., E.D. Hausman, B. Biewald, R. Wilson, and D. White. *2011 Carbon Dioxide Price Forecast*. Synapse Energy Economics White Paper, February 2011.

Hausman E.D., V. Sabodash, N. Hughes, and J. I. Fisher, *Economic Impact Analysis of New Mexico's Greenhouse Gas Emissions Rule*. Synapse Energy Economics for New Energy Economy, February 2011.

Hausman E.D., J. Fisher, L. Mancinelli, and B. Biewald. *Productive and Unproductive Costs of CO₂ Cap-and-Trade: Impacts on Electricity Consumers and Producers*. Synapse Energy Economics for National Association of Regulatory Utility Commissioners, National Association of State Utility Consumer Advocates, National Rural Electric Cooperative Association, and American Public Power Association, July 2009.

Peterson P., E. Huasman, R. Fagan, and V. Sabodash, *Report to the Ohio Office of Consumer Counsel, on the value of continued participation in RTOs. Filed under Ohio PUC Case No. 09-90-EL-COI*, May 2009.

Schlissel D., L. Johnston, B. Biewald, D. White, E. Hausman, C. James, and J. Fisher, *Synapse 2008 CO₂ Price Forecasts*. July 2008.

Hausman E.D., J. Fisher and B. Biewald, *Analysis of Indirect Emissions Benefits of Wind, Landfill Gas, and Municipal Solid Waste Generation*. Synapse Energy Economics Report to the Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, U.S. Environmental Protection Agency, July 2008.

Hausman E.D. and C. James, *Cap and Trade CO₂ Regulation: Efficient Mitigation or a Give-away?* Synapse Enegy Ecomics presentation to the ELCON Spring Workshop, June 2008.

Hausman E.D., R. Hornby and A. Smith, *Bilateral Contracting in Deregulated Electricity Markets*. Synapse Energy Economics for the American Public Power Association, April 2008.

Hausman E.D., R. Fagan, D. White, K. Takahashi and A. Napoleon, *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers*. Synapse Energy Economics for the American Public Power Association's Electricity Market Reform Initiative (EMRI) symposium, "Assessing Restructured Electricity Markets" in Washington, DC, February 2007.

Hausman E.D. and K. Takahashi, *The Proposed Broadwater LNG Import Terminal Response to Draft Environmental Impact Statement and Update of Synapse Analysis*. Synapse Energy Economics for the Connecticut Fund for the Environment and Save The Sound, January 2007.

Hausman E.D., K. Takahashi, D. Schlissel and B. Biewald, *The Proposed Broadwater LNG Import Terminal: An Analysis and Assessment of Alternatives*. Synapse Energy Economics for the Connecticut Fund for the Environment and Save The Sound, March 2006.

Hausman E.D., P. Peterson, D. White and B. Biewald, *RPM 2006: Windfall Profits for Existing Base Load Units in PJM: An Update of Two Case Studies*. Synapse Energy Economics for the Pennsylvania Office of Consumer Advocate and the Illinois Citizens Utility Board, February 2006.

Hausman E.D., K. Takahashi, and B. Biewald, *The Glebe Mountain Wind Energy Project: Assessment of Project Benefits for Vermont and the New England Region*. Synapse Energy Economics for Glebe Mountain Wind Energy, LLC., February 2006.

Hausman E.D., K. Takahashi, and B. Biewald, *The Deerfield Wind Project: Assessment of the Need for Power and the Economic and Environmental Attributes of the Project*. Synapse Energy Economics for Deerfield Wind, LLC., January 2006.

Hausman E.D., P. Peterson, D. White and B. Biewald, *An RPM Case Study: Higher Costs for Consumers, Windfall Profits for Exelon*. Synapse Energy Economics for the Illinois Citizens Utility Board, October 2005.

Hausman E.D. and G. Keith, *Calculating Displaced Emissions from Energy Efficiency and Renewable Energy Initiatives*. Synapse Energy Economics for EPA website 2005

Rudkevich A., E.D. Hausman, R.D. Tabors, J. Bagnal and C Kopel, *Loss Hedging Rights: A Final Piece in the LMP Puzzle*. Hawaii International Conference on System Sciences, Hawaii, January, 2005 (accepted).

Hausman E.D. and R.D. Tabors, *The Role of Demand Underscheduling in the California Energy Crisis*. Hawaii International Conference on System Sciences, Hawaii, January 2004.

Hausman E.D. and M.B. McElroy, *The reorganization of the global carbon cycle at the last glacial termination*. *Global Biogeochemical Cycles*, 13(2), 371-381, 1999.

Norton F.L., E.D. Hausman and M.B. McElroy, *Hydrospheric transports, the oxygen isotope record, and tropical sea surface temperatures during the last glacial maximum*. *Paleoceanography*, 12, 15-22, 1997.

Hausman E.D. and M.B. McElroy, *Variations in the oceanic carbon cycle over glacial transitions: a time-dependent box model simulation*. Presented at the spring meeting of the American Geophysical Union, San Francisco, 1996.

PRESENTATIONS AND WORKSHOPS

ELCON 2011 Fall Workshop: "Do RTOs Need a Capacity Market?" October 2011.

Harvard Electricity Policy Group: Presentation on state action to ensure reliability in the face of capacity market failure. February 2011.

NASUCA 2010 Annual Conference: “Addressing Climate Change while Protecting Consumers.” November 2010.

NASUCA Consumer Protection Committee: Briefing on the Synapse report entitled, “Productive and Unproductive Costs of CO₂ Cap-and-Trade.” September 2009.

NARUC 2009 Summer Meeting: Invited speaker on topic: “Productive and Unproductive Costs of CO₂ Cap-and-Trade.” July, 2009.

NASUCA 2008 Mid-Year Meeting: Invited speaker on the topic, “Protecting Consumers in a Warming World, Part II: Deregulated Markets.” June 2008.

Center for Climate Strategies: Facilitator and expert analyst on state-level policy options for mitigating greenhouse gas emissions. Serve as facilitator/expert for the Electricity Supply (ES) and Residential, Commercial and Industrial (RCI) Policy Working Groups in the states of Colorado and South Carolina. 2007-2008.

NASUCA 2007 Mid-Year Meeting: Invited speaker on the topic, “Protecting Consumers in a Warming World” June 2007.

ASHRAE Workshop on estimating greenhouse gas emissions from buildings in the design phase: Participant expert on estimating displaced emissions associated with energy efficiency in building design. Also hired by ASHRAE to document and produce a report on the workshop. April, 2007.

Assessing Restructured Electricity Markets An American Public Power Association Symposium: Invited speaker on the history and effectiveness of Locational Marginal Pricing (LMP) in northeastern United States electricity markets, February, 2007.

ASPO-USA 2006 National Conference: Invited speaker and panelist on the future role of LNG in the U.S. natural gas market, October, 2006.

Market Design Working Group: Participant in FERC-sponsored settlement process for designing capacity market structure for PJM on behalf of coalition of state utility consumer advocates, July-August 2006.

NASUCA 2006 Mid-Year Meeting: Invited speaker on the topic, “How Can Consumer Advocates Deal with Soaring Energy Prices?” June 2006.

Soundwaters Forum, Stamford, CT: Participated in a debate on the need for proposed Broadwater LNG terminal in Long Island Sound, June 2006.

Energy Modeling Forum: Participant in coordinated academic exercise focused on modeling US and world natural gas markets, December 2004.

Massachusetts Institute of Technology (MIT): Guest lecturer in Technology and Policy Program on electricity market structure, the LMP pricing system and risk hedging with FTRs. 2002-2005.

LMP: The Ultimate Hands-On Seminar. Two-day seminar held at various sites to explore concepts of LMP pricing and congestion risk hedging, including lecture and market simulation exercises. Custom seminars held for FERC staff, ERCOT staff, and various industry groups. 2003-2004.

Learning to Live with Locational Marginal Pricing: Fundamentals and Hands-On Simulation. Day-long seminar including on-line mock electricity market and congestion rights auction, December 2002.

LMP in California. Series of seminars on the introduction of LMP in the California electricity market, including on-line market simulation exercise. 2002.

Resume updated June 2014

Exhibit EDH-2

Direct testimony of Mr. Patrick Dinkel on behalf of
Arizona Public Service Corp., ACC Docket No.
E-01345A-10-0474, Dated November 22, 2010.

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DIRECT TESTIMONY OF PATRICK DINKEL

On Behalf of Arizona Public Service Company

Docket No. E-01345A-10-_____

November 22, 2010

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**DIRECT TESTIMONY OF PATRICK DINKEL
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-10-)**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is Patrick Dinkel. I am the Vice President of Power Marketing, Resource Planning and Acquisition at Arizona Public Service Company ("APS" or "Company"). In that capacity, I am responsible for power marketing and trading, the integrated resource planning function, long-term generation acquisition, and the Company's Renewable Energy Program.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree from Marymount College and a Master of Business Administration from Northern Arizona University. I joined APS in 1986. Prior to being named Vice President of Power Marketing and Resource Planning and Acquisition, I was General Manager of Strategic Planning and Resource Acquisition, where I was also responsible for overseeing APS's long-term power procurement and renewable energy programs. Before that, I was Director of Resource Acquisitions and Renewable Energy, and have also been responsible for Corporate Planning and Business Unit Analysis and Reporting. During my career at APS, I have held various positions within APS and Pinnacle West Capital Corporation, primarily within the renewable energy, financial, and budgeting areas.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION ("COMMISSION")?

A. Yes. I testified in support of APS's requests to acquire the Sundance Assets (Docket No. E-01345A-04-0407), and, later, to include those assets in rate base (Docket No. E-01345A-05-0816). I also testified in support of APS's request for authorization to acquire the Yuma Assets (Docket No. E-01345A-06-0464), in

1 support of the Commission's grant of a Certificate of Environmental
2 Compatibility for Abengoa Solar (Docket No. L-00000GG-08-0407-00139 and
3 L-00000GG-08-0408-00140), and in the recent APS rate case (Docket No. E-
4 01345A-08-0172).

5 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**
6 **PROCEEDING?**

7 A. My testimony supports APS's application for authorization and other support
8 needed to purchase Southern California Edison's ("SCE") existing ownership
9 interest in Four Corners Power Plant ("Four Corners") Units 4 and 5 and retire
10 Units 1-3 of that plant. Specifically, I will describe how that transaction benefits
11 APS customers and makes good business sense from a resource planning
12 perspective.

13 **II. THE PROPOSED TRANSACTION BENEFITS CUSTOMERS.**

14 **Q. YOU NOTED ABOVE THAT APS'S PROPOSAL TO ACQUIRE SCE'S**
15 **SHARE OF FOUR CORNERS AND RETIRE UNITS 1-3 BENEFITS**
16 **CUSTOMERS. PLEASE ELABORATE.**

17 A. Simply put, the proposed transaction is the best value for APS customers
18 compared to every reasonable resource alternative. Let me explain. The energy
19 APS receives from its current ownership interest in the Four Corners generating
20 station Units 4 and 5 represents 6% of APS's energy resources. If no one
21 acquires SCE's ownership interest in Four Corners, there is a risk that the co-
22 owners of Units 4 and 5 will choose to retire those units. A shutdown of Units 4
23 and 5 results in APS losing 231 MW of a reliable and economic baseload
24 resource now serving APS customers.

25 Four Corners Units 1-3 provide APS customers with 560 MW, or 4200 GWH, of
26 baseload energy. Although Units 1-3 currently comply with all environmental
27 regulations, they will require significant environmentally-driven capital
28 investment over the next five years if they are to remain in service. The first

1 expected tranche, \$235 million for mercury emission controls, could come as
2 early as 2014; the second, a potential \$351 million to comply with the EPA's
3 proposed Best Available Retrofit Technology ("BART") visibility requirements,
4 is due as early as 2016. Units 1-3 are cost-effective for APS customers now, but
5 that may no longer be true if a total of \$586 million must be spent in five short
6 years to keep them online. Other costs may also be required for those units to
7 comply with future greenhouse gas regulations. In other words, there is a risk
8 that all of Four Corners could close by 2016.

9
10 If all five units are retired, APS will lose 791 MW of low-cost base load
11 generation that currently provides 19% of APS total generation needs. Navajo
12 Generating Station, in which APS, SRP, and TEP each own a share, faces many
13 of the same issues. If it closes, APS would lose yet another 315 MW of baseload
14 capacity, posing the risk that APS could lose 1,106 MW – that is 26% of its
15 energy – in just a few years.

16 **Q. WHAT ALTERNATIVE RESOURCES ARE AVAILABLE TO REPLACE**
17 **LOST FOUR CORNERS GENERATION?**

18 A. Coal is a baseload resource and a fundamental component of APS's energy mix.
19 A baseload resource is one that is designed to run 24 hours a day, seven days a
20 week, to meet the Company's lowest around-the-clock demand. Continually
21 called on, such a resource must be both reliable and cost-effective, or else
22 customers will pay more for their energy. Potential replacement alternatives for
23 any lost Four Corners generation include coal and nuclear (large, conventional
24 "baseload" resources), geothermal and biomass/biogas (small, renewable
25 baseload resources), and natural gas (an "intermediate" resource that is reliable
26 although it has greater fuel cost volatility compared to others and is most cost-
27 effective when serving peak load). Solar and wind generation, while increasingly
28 important components of APS's energy mix, are intermittent resources that a

1 utility cannot control and that cannot adequately substitute for one that is required
2 night and day, 365 days each year.

3 **Q. MORE SPECIFICALLY, ASSUMING THAT PLANT PARTICIPANTS**
4 **OPT TO CLOSE UNITS 4 AND 5 IN 2016, HOW WOULD APS REPLACE**
5 **THE RESULTING 231 MW CAPACITY LOSS?**

6 A. Few of the alternative resources discussed in my prior answer are realistically
7 available to fill the energy void left APS if Four Corners Units 4 and 5 were to
8 shut down in 2016. Arizona does not have sufficient geothermal resources to
9 provide such capacity, and the geothermal that is available in Southern California
10 has many potential buyers competing for this limited resource. Any geothermal
11 plant that might be constructed would be too small (e.g., 50 MW) to address the
12 void left by the retirement of the coal plants. Arizona also has highly limited
13 amounts of biogas and biomass available, and APS will continue to seek those
14 resources irrespective of the outcome of this application. Nuclear energy takes at
15 least ten years to develop, and requires a large upfront capital investment.
16 Putting aside that capital outlay, a new nuclear resource would certainly not be
17 available until several years past the 2016 need date. While energy efficiency
18 will fill a portion of these requirements, APS is already committed to
19 aggressively pursuing its cost effective energy efficiency programs. In any case,
20 energy efficiency cannot be a complete solution – a point well-demonstrated in
21 Graph 4 on page 11 of my Testimony, which compares what APS's energy mix
22 will look like if the Company's Application is approved to what it will be if it is
23 not.

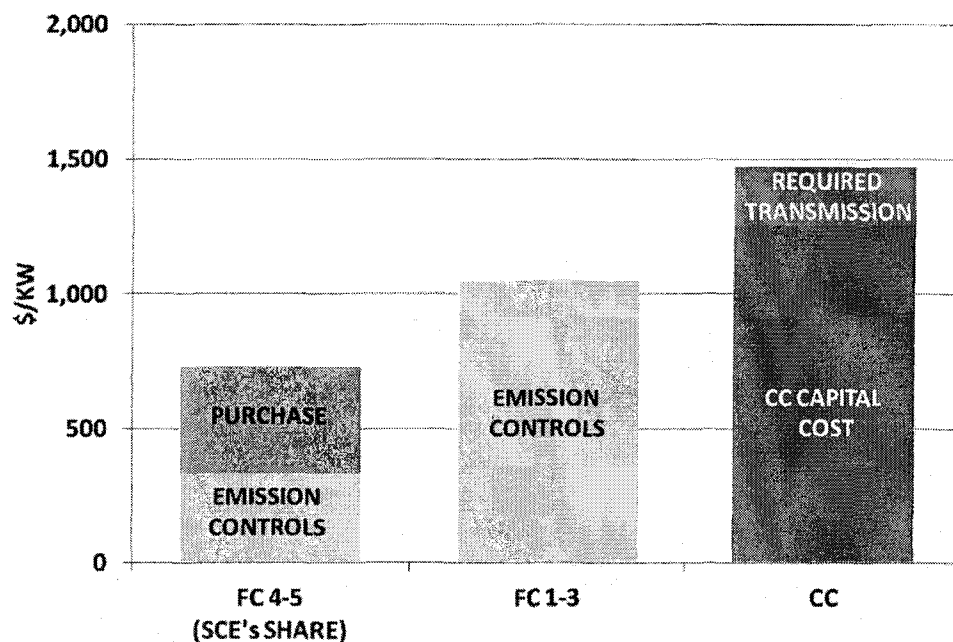
24 This leaves APS with three potential options: (1) continue to operate Units 1-3
25 (which still leaves APS 231 MW short in 2016 if Units 4 and 5 shutdown,
26 possibly rising to 546 MW if Navajo Generating Station retires); (2) replace any
27 power lost from Four Corners with combined-cycle gas generation; or (3) retire
28

Units 1-3 and acquire SCE's interest in Units 4-5. Analysis of these options clearly shows that it is most beneficial to APS customers to retire Units 1-3 early and replace their output with the purchase of SCE's interest in Units 4 and 5.

Q. OF THE OPTIONS YOU DESCRIBE, WHY IS THE TRANSACTION PROPOSED IN THE COMPANY'S APPLICATION THE MOST BENEFICIAL TO CUSTOMERS?

A. There are several reasons. First, from a cost perspective, customers will pay less under the proposed transaction than under either of the alternatives. This point is well demonstrated in the following two graphs, as well as through traditional revenue requirements analysis.

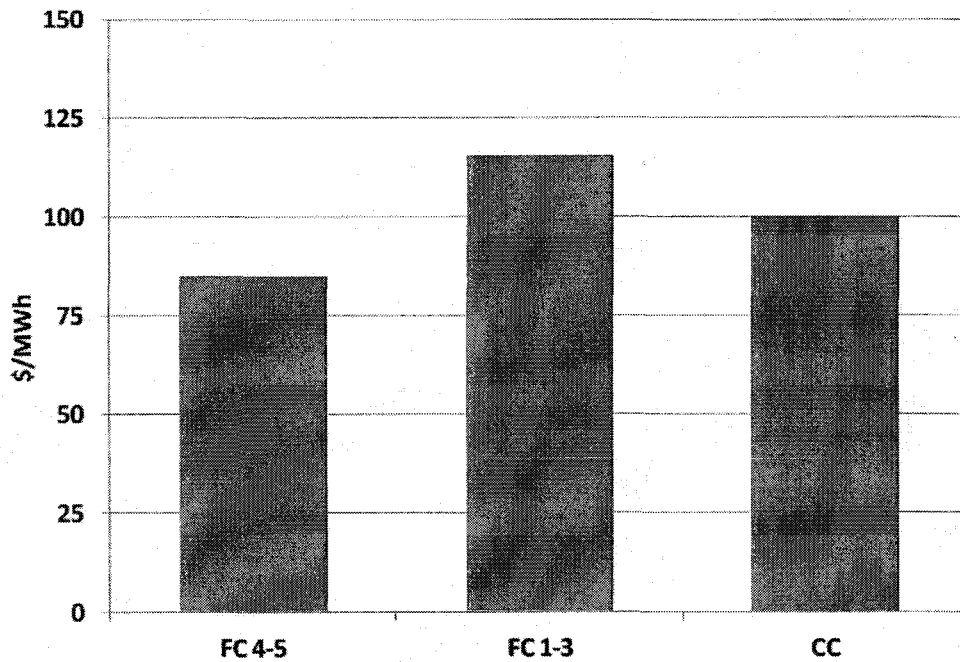
GRAPH 1: CAPITAL COST COMPARISON



Graph 1 compares, on a dollar per kilowatt basis, the initial capital dollars that APS would pay for various generation resources. For the Four Corners-related alternatives, the noted value includes the cost of installing all required environmental controls, a \$294 million cash acquisition price, and the assumption of certain decommissioning and mine reclamation liabilities for SCE's additional

1 739 MW.¹ The graph shows that consummating the proposed transaction and
2 installing potential environmental upgrades at Units 4 and 5 is the lowest cost
3 alternative in terms of up-front cost.
4

5 **GRAPH 2: LIFE CYCLE LEVELIZED COSTS**



17
18 Graph 2 compares, on a dollar per megawatt hour basis, the total cost of the
19 generation resource, fully integrated into the electrical system, levelized over the
20 full life cycle of the plant. For the Four Corners-related alternatives, the noted
21 values include the cost of the environmental upgrades and an assumed
22 internalized carbon price of \$20/ton, beginning in 2013. The current carbon price
23 is \$0/ton; however, we believe the cost of carbon should be considered as an
24 environmental factor in the resource decision-making process. This graph shows
25 that the proposed transaction is the lowest cost for customers over the project life,
26 compared to the alternatives.

27 ¹ See Testimony of Mark Schiavoni at 6-7 for a description of the Purchase and Sale Agreement between
28 APS and SCE.

1 Finally the cost of the alternatives can be communicated in terms of the net
2 present value of customer revenue requirements. In comparing these three
3 alternatives, the acquisition of SCE's share of Units 4-5 results in a revenue
4 requirement that is \$500 million less than the alternative of replacing the retired
5 Four Corners energy with natural gas generation. The proposed transaction also
6 results in a revenue requirement that is \$1 billion less than the alternative of
7 investing in and continuing to run Units 1-3 over the same timeframe.
8

9 It is clear that none of the alternative resource scenarios brings the same cost
10 benefit to APS customers as that proposed here. Consider the potential for
11 keeping Units 1-3 in service, for example. In that case, as Graph 1 illustrates,
12 APS customers will pay 44% more in capital costs to install the emission controls
13 likely needed on Units 1-3 to keep those units in service than they will under the
14 proposed transaction, an analysis that includes the cost of making the necessary
15 environmental upgrades on Units 4 and 5. Moreover, this option simply
16 preserves a resource that is already serving APS customers and does nothing to
17 replace the other 231 MW of cost-effective generation that APS would forego if
18 Units 4 and 5 retire in 2016, or protect against the potential loss of another 315
19 MW at Navajo Generating Station not long thereafter. APS customers would
20 incur that much more in replacement power costs if the Company pursued this
21 option.
22

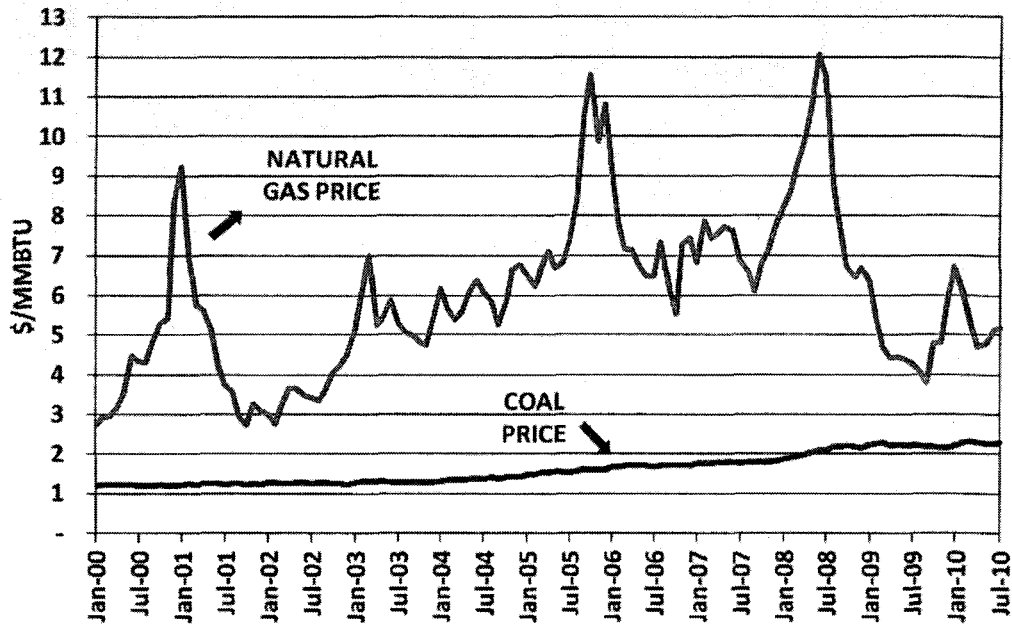
23 Retiring Units 4 and 5 in favor of Units 1-3 also makes little sense from an
24 operational perspective, given that Units 1-3 are smaller and less efficient, and
25 lack the same economies of scale benefits of Units 4 and 5. By way of example,
26 the cost of installing SCRs on Units 1-3 is approximately \$627 per kW, while the
27 cost of installing the same equipment on Units 4-5 is roughly \$325 per kW – a
28 significant difference.

1 **Q. YOU NOTED THAT NATURAL GAS WAS A SECOND ALTERNATIVE**
2 **TO THE PROPOSED TRANSACTION. PLEASE DISCUSS THAT**
3 **OPTION.**

4 A. Natural gas generation is a reliable economic resource which effectively meets
5 the marginal resource needs of a utility. It has been the "measuring stick" that
6 APS has used in recent years when evaluating all resource alternatives –
7 conventional or renewable. However, the drawbacks of using natural gas to
8 replace 231 MW or more of existing Four Corners capacity are significant. First,
9 the gas option is much more expensive than the approach proposed in the
10 Company's Application. Apart from the capital costs associated with additional
11 combined cycle generation, a new gas resource would require APS both to build
12 new transmission infrastructure, and to maintain the current schedule of now-
13 planned transmission lines. As Graph 1 on page 5 of my Testimony shows, the
14 cost of building new combined-cycle and transmission infrastructure is double the
15 cost of purchasing SCE's share of Units 4 and 5 and installing the required
16 environmental controls on those units, on a dollar per kilowatt basis. Moreover,
17 as Graph 2 depicts, APS customers will pay almost 20% more per megawatt hour
18 over the life cycle of a new gas plant than they will if APS acquires SCE's
19 interest in Units 4 and 5.

20 In addition, unlike Four Corners' fuel costs, made dependable by virtue of a
21 negotiated long-term fuel agreement with the supplier, gas prices are highly
22 volatile, as well-evidenced by the following graph:
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24
25
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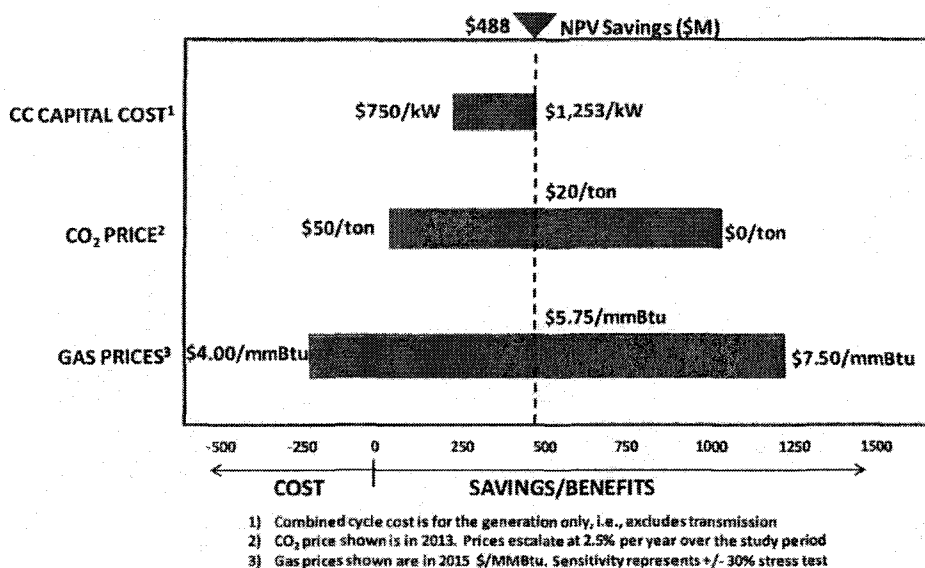
GRAPH 3: HISTORICAL U.S. FOSSIL FUEL PRICES



Source: U.S. Energy Information Administration; October 2010 Monthly Energy Review; Table 9.10, Cost of Fossil-Fuel Receipts at Electric Generating Plants

APS has conducted sensitivity analyses that demonstrate that the economic advantage of acquiring SCE's interest in Four Corners persists over a wide range of factors. In order to break even with the life cycle cost of the proposed transaction, natural gas prices would have to be 20% lower than the current long-term forecast. Or, the price assigned to carbon would have to rise above \$50 per ton. Alternatively, replacement combined-cycle gas costs would have to be half of current cost estimates to build that resource. The following illustrates these sensitivities:

APS CUSTOMER BENEFITS DUE TO SCE TRANSACTION

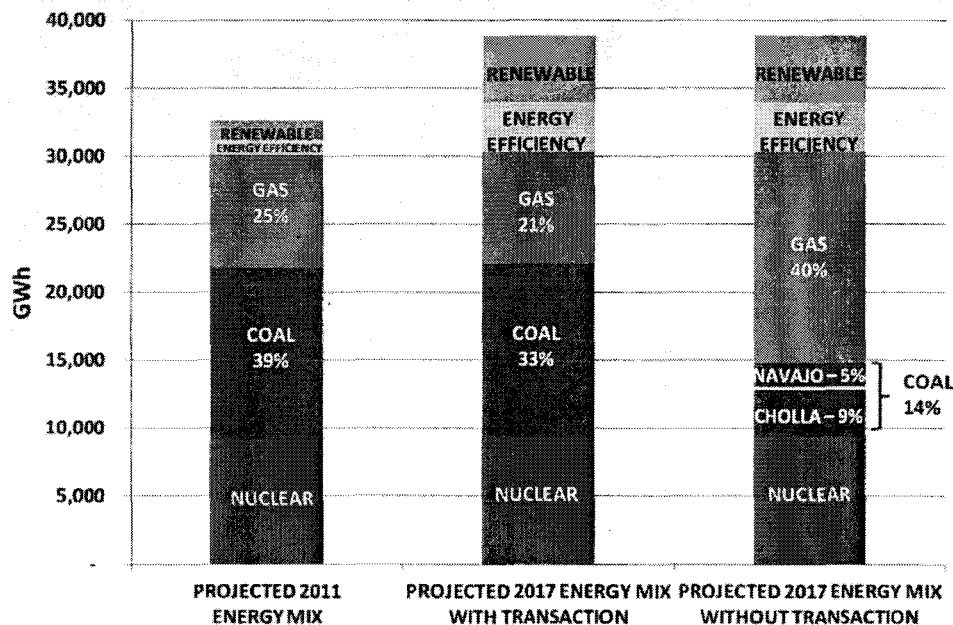


Gas is a reliable resource that has an important place in a utility's resource portfolio, but if APS's resource mix becomes too dependent on natural gas, our customers will be highly exposed to potential fuel cost increases and volatility. APS's resource choices, like those of all power generators, each have a variety of trade-offs. This is why having a diverse energy mix, which reduces reliance on any single power source, mitigates risk and makes good business sense.

Q. HOW WOULD REPLACING APS'S SHARE OF ITS EXISTING FOUR CORNERS COAL CAPACITY WITH NATURAL GAS IMPACT THE COMPANY'S RESOURCE PORTFOLIO?

A. As Graph 4 shows, if APS replaces 791 MW of its existing coal capacity with natural gas generation, the Company's resource diversity decreases and customer reliance on natural gas generation increases by 90%, with natural gas making up 40% of the Company's generation. Having 40% of the Company's generation dependent upon potentially volatile natural gas markets would put APS and its customers at a significantly higher level of risk.

GRAPH 4: TRANSACTION MAINTAINS DIVERSE ENERGY MIX FOR APS



Q. ARE THERE ANY OTHER REASONS WHY THE NATURAL GAS ALTERNATIVE IS A LESS PREFERABLE ONE?

A. Yes. There is also a practical risk to replacing the Four Corners output with natural gas. Additional gas generation and the associated transmission must be sited, permitted and constructed in a very short time frame if it is to be serving APS customers by 2016. As with any construction project, there is always the risk that projects will be delayed and the resources will not be available to customers when needed. Moreover, to execute this contingency, APS's currently planned and certificated Morgan to Sun Valley transmission line (commonly known as "TS-5 to TS-9") would need to be energized by 2016 – a feat which may prove difficult given the unresolved right-of-way issues for that project. The tight time clock not only makes the Four Corners alternative more appealing, but demonstrates the practical need for having this application processed quickly.

1 **Q. DOES APS HAVE A NEED FOR THE CAPACITY IT WILL ACQUIRE**
2 **AS A RESULT OF THIS TRANSACTION?**

3 A. Yes, it does. APS's Loads and Resource table ("L&R"), attached to my
4 Testimony as Attachment PD-1, shows that APS will require another 545 MW of
5 resources to meet its 2017 load requirements even if this transaction moves
6 forward. That calculation also assumes the addition of over 1400 MW of
7 renewable resources and energy efficiency programs. If the proposed transaction
8 fails, APS's need for new resources could increase to over 1,500 MWs in 2017.
9 Output from Navajo Generating Station may also be lost to similar
10 vulnerabilities, giving need for yet another 315 MW of replacement power. Were
11 both Four Corners and Navajo Generating Station to shut down entirely, APS's
12 existing base load resources would be limited to Cholla Power Plant (providing a
13 total of 647 MW) and Palo Verde Nuclear Generating Station (providing 1,146
14 MW) – a total of 1,793 MW to serve a 2020 minimum system demand of 2,530
15 MW. Such a scenario would dramatically increase APS's reliance on natural gas
16 and our customers' exposure to gas price volatility.

17 Given that potential, the long-term need for maintaining sufficient, reliable base
18 load resources is clear. The proposed transaction essentially preserves a well-
19 balanced energy supply portfolio for APS, with a slight net increase of 179 MW –
20 a small difference that is unavoidable under the circumstances. That additional
21 179 MW provides protection against volatile natural gas prices as well as the
22 potential loss of the Navajo Generating Station capacity. APS also expects to
23 further defer the need for new base load generation if the transaction is approved.

24 **Q. DID APS CONSIDER PROCURING RESOURCES FROM THE**
25 **COMPETITIVE WHOLESALE MARKET AS AN ALTERNATIVE TO**
26 **THE PROPOSED TRANSACTION?**

27 Yes. APS has looked at what exists in the competitive wholesale market, but
28 none of its offerings reasonably compare to the transaction with SCE. As

1 discussed above, gas-fired generation – the most practical alternative to Four
2 Corners in these circumstances – would further expose APS customers to
3 uncertain gas prices and require that new transmission be built for any gas-fired
4 power to reach the Company's primary load center in the Metropolitan Phoenix
5 area. Any potential plant acquisition price is especially uncertain given the fact
6 that the need would not be until 2017. Although APS might also procure new
7 coal, any such resource would have significant development risk, a cost well
8 above that of the Four Corners acquisition price, and could not be built in time to
9 meet the Company's need.

10 **Q. IS THE APPROACH OUTLINED IN APS'S APPLICATION**
11 **CONSISTENT WITH ITS LONG-TERM RESOURCE PLAN?**

12 A. Yes. APS's L&R table indicates that, even after acquiring SCE's share of Four
13 Corners Units 4 and 5 and retiring Units 1-3, APS will still need over 500 MWs
14 of resources in the 2017 timeframe. This L&R table also includes APS's
15 commitment to exceed compliance with the Renewable Energy Standard, and
16 meet the Commission's ambitious and recently adopted Energy Efficiency
17 Standard. The Resource Plan currently on file with the Commission also stresses
18 the value of maintaining a diverse energy supply portfolio – one that balances
19 coal, gas, and nuclear generation to complement the ever-growing role of
20 renewable resources and energy efficiency in meeting its customers' energy
21 needs. Acquiring the SCE interest in Units 4 and 5, combined with the early
22 retirement of Units 1-3, is thus fully consistent with the Company's resource
23 plans.

24 **Q. THE APPLICATION REQUESTS THAT THE COMMISSION RULE ON**
25 **THIS MATTER EXPEDITIOUSLY. WHY IS THAT IMPORTANT?**

26 A. If the Commission rejects the Company's requests, Four Corners Units 4 and 5,
27 and possibly Units 1-3, risk closing no later than 2016. APS must start working
28 to implement a contingency plan, accelerating the acquisition and construction of

1 new generation and transmission infrastructure and/or installing emission control
2 devices on Units 1-3. Without a timely order from this Commission, time may
3 run out to construct or buy new replacement generation.

4 **III. CONCLUSION**

5 **Q. DO YOU HAVE ANY CONCLUDING REMARKS TO YOUR**
6 **TESTIMONY?**

7 **A.** The proposal outlined in the Company's Application simply makes good sense
8 for APS and our customers. It has the lowest relative capital cost, greatest cost
9 certainty, and allows APS to maintain a reliable and cost-effective source of base
10 load generation – all while improving the plant's environmental impact and
11 stabilizing the local economies, as APS witness Mark Schiavoni describes. It
12 also has the lowest customer rate impact, as APS witness Jeff Guldner explains.
13 Although, there will be significant capital cost requirements in the short term, the
14 approach outlined in this application provides nearly a \$500 million net present
15 value benefit to APS customers. This opportunity is fully consistent with APS's
16 obligation to provide cost effective, reliable, and environmentally conscious
17 service to our customers and the communities we serve. It is one worth seizing.

18 **Q. DOES THAT CONCLUDE YOUR TESTIMONY?**

19 **A.** Yes.
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Exhibit EDH-3

APS response to Sierra Club Data Request 2.1

**This exhibit is confidential and is provided under
separate cover.**

Exhibit EDH-4

APS response to Sierra Club Data Request 2.4

**This exhibit is confidential and is provided under
separate cover.**

Exhibit EDH-5

APS response to Staff Data Request 35.35

**This exhibit is confidential and is provided under
separate cover.**

Exhibit EDH-6

“Greenhouse Gas Legislative Review and CO2 Price Outlook”, prepared by Charles River Associates on behalf of Arizona Public Service Corp, and attached as Appendix A to APS’s 2012 Integrated Resource Plan. Dated November 4, 2011.



Arizona Public Service

Greenhouse Gas Legislative Review and CO₂ Price Outlook

Prepared By:

Barclay Gibbs

Charles River Associates

1201 F Street NW

Suite 700

Washington, DC 20004

November 4, 2011

Barclay Gibbs consults to electric utilities, power project investors, and large industrial users of electricity. Using CRA's proprietary North American Electricity & Environment Model (NEEM), Mr. Gibbs has evaluated the impact of various Federal and state policies on generation technology expansion plans, electricity prices, and generation asset value. He has evaluated the reliability implications of proposed federal air pollution regulations and forecasted SO₂ and NO_x prices under those regulations, forecasted prices for Renewable Energy Credits (RECs), assessed the costs and benefits of expanding transmission to access remote windpower, evaluated the producer and consumer impacts of proposed export tariff changes in a North American electricity market, and forecasted the fuel cost pass-through from a utility to a large industrial user of electricity. Recently, he has worked on a market power evaluation of various proposed allocation schemes under EPA's proposed Clean Air Transport Rule (CATR). He also assessed the impacts of short-term coal market constraints on allowance prices under EPA's final Cross-State Air Pollution Rule (CSAPR). Prior to joining CRA International, Mr. Gibbs was a managing consultant in the Technology Strategy and Management Group at Navigant Consulting where he consulted on energy efficiency policy and bioenergy. Mr. Gibbs holds an M.S. in Technology & Policy from Massachusetts Institute of Technology, an M.A. in Applied Economics from Johns Hopkins University, an M.S. in Environmental Systems Engineering from Clemson University, and a B.S. in Chemical Engineering from Bucknell University.

The conclusions set forth herein are based on independent research and publicly available material. The views expressed herein are the views and opinions of the author and do not reflect or represent the views of Charles River Associates or any of the organizations with which the author is affiliated. Any opinion expressed herein shall not amount to any form of guarantee that the author or Charles Rivers Associates has determined or predicted future events or circumstances, and no such reliance may be inferred or implied. The author and Charles River Associates accept no duty of care or liability of any kind whatsoever to any party, and no responsibility for damages, if any, suffered by any party as a result of decisions made, or not made, or actions taken, or not taken, based on this paper. Detailed information about Charles River Associates, a registered trade name of CRA International, Inc., is available at www.crai.com.

Introduction

Arizona Public Service (APS) is embarking on its 2012 Integrated Resource Planning (IRP) process. In early August 2011, APS engaged Charles River Associates (CRA) to provide a review of recent Greenhouse Gas (GHG) policy developments and the current outlook for Federal CO₂ pricing. This policy paper reviews the major recent developments in GHG policy, discusses some of the more significant and recent legislative proposals to curb U.S. GHG emissions, and provides recommendations for CO₂ prices in the current APS IRP.

Exhibit 1 summarizes some of the major historical elements of GHG policy development over the last 20 years, with particular emphasis on the more recent years. During the years 2007-2010, many federal legislative proposals addressing climate change surfaced. Since the summer of 2010, there has been almost no attention on federal climate change legislation. The policy debate in Washington has shifted more to EPA actions such as the Cross-State Air Pollution Rule (CSAPR), Air Toxics (formerly Utility MACT), once-through cooling regulations (316b), coal ash regulation, and EPA's own regulation of GHGs.

Exhibit 1. GHG Policy Timeline

Event	Description	Year	Comment
UN Framework Convention on Climate Change (UNFCCC), Rio de Janeiro	Nations agree to voluntary reduction of emissions, with "common but differentiated responsibilities"	1992	This "Earth Summit" is often cited as the beginning of global climate policy negotiation
Kyoto Protocol negotiated	First Internationally Binding Treaty; 160 Countries; 37 Developed Nations agree to cut emissions 5% below 1990 levels by 2012	1997	The Kyoto Protocol was never submitted to the US Senate for ratification
McCain (R-AZ) -Lieberman (D-CT) Climate Stewardship Act proposed in US Senate	First major U.S. Climate Bill	2003	Defeated in the Senate 55-43
European Emissions Trading System (ETS) begins	Europe establishes a cap-and-trade system for CO ₂ , aimed at Kyoto compliance	2005	Controversies over profits based on allocation scheme
California's AB32 Policy signed into Law	Emissions reduction goals are roughly in-line with Kyoto	2006	Cap-and-trade start date was recently delayed until 2013
Bingaman (D-NM) – Specter (R-PA) propose the Low Carbon Economy Act of 2007	Cap-and-trade climate bill with a relatively low safety valve (called a Technology Accelerator Payment, TAP) of \$12/tonne of CO ₂ Eq.	2007	Bill never made it out of the Senate Environment and Public Works committee
Lieberman (I-CT) –Warner (R-VA) Climate Security Act	Highly prominent climate bill makes it to main Senate floor but dies in a procedural vote	Oct 2007- June 2008	June 2008 marks the end of significant climate change debate during the Bush Administration

Exhibit 1. GHG Policy Timeline (cont.)

RGGI Cap-and-Trade program begins	10 Northeast states begin cap-and-trade policy that reduces emissions by 10% by 2018	Fall 2008	Allowances have typically traded at the minimum reservation price in recent years. <i>Gov. Chris Christie has recently announced withdrawal of NJ.</i>
Waxman (D-CA) –Markey (D-MA) American Clean Energy and Security Act (ACES) is passed by the House		June 2009	Reflects optimism for US Climate legislation in the early days of the Obama administration
A bill competing with Waxman-Markey is introduced	Kerry (D-MA) – Boxer (D-CA)	Fall 2009	
Conference of Parties 15 (COP15), Copenhagen Accord	High-profile, regular meeting of the Conference of the Parties to the UNFCCC	Dec. 2009	Non-binding agreement on emissions targets. A significant outcome was \$100B/yr pledged from rich countries to poor countries. Generally viewed as achieving less progress than anticipated.
Negotiations on a grand compromise involving Senators Kerry (D-MA), Lieberman (I-CT), and Graham (R-SC) break down	Graham withdraws from negotiations, citing immigration politics	April 2010	Symptomatic of intensifying partisanship in Washington, particularly around regulation
Kerry (D-MA) – Lieberman (I-CT) American Power Act is proposed	The two senators move forward without Senator Graham	May 2010	Nothing substantial happened with this proposal
Waxman (D-CA) -Markey (D-MA) American Clean Energy and Security Act (ACES) dies in the Senate	Originally passed by the House in June 2009, the Waxman-Markey bill dies in the Senate	June 2010	Climate change legislation takes a back seat to other priorities on Capitol Hill.
The US House of Representatives becomes Republican-controlled and the Democratic majority in the Senate is weakened	Anti-regulation sentiment by incoming Republicans diminishes chances for comprehensive U.S. Climate policy, particularly under current economic conditions	Nov. 2010	
EPA prepares to regulate GHGs as part of NSPS		Scheduled 2011	

Summary of Recent Greenhouse Gas Policy Developments

Recent Federal Legislative Proposals

Bingaman-Specter (S.1766, Low Carbon Economy Act of 2007)

The Bingaman-Specter bill was introduced by Senators Jeff Bingaman (D-NM) and Arlen Specter (R-PA) in July 2007. The bill was more modest in its emissions reduction goals than many of the other major climate proposals. Its goals were to reduce economy-wide GHG emissions to 2006 levels by 2020 and to 1990 levels by 2030. In addition, the bill contained a cost-containment provision called the Technology Accelerator Payment (TAP) which was essentially a safety valve price of \$12/tonne CO₂ Eq. starting in 2012, rising at 5% above inflation.¹ The TAP would have been paid into a fund that would have been used to hasten low-carbon technology development.

The Low Carbon Economy Act of 2007 never made it out of the Senate Environment and Public Works Committee.

Lieberman-Warner (S.2191, America's Climate Security Act)

The Lieberman-Warner bill was a high-profile piece of legislation introduced by Senators Joseph Lieberman (I-CT) and John Warner (R-VA) during October 2007. It was later amended by the Boxer amendment (D-CA). The cap-and-trade policy would have covered more than 75% of U.S. GHG emissions, including the six major GHGs (CO₂, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons) emitted from the electric, industrial, and transportation sectors. The proposal would have capped U.S. emissions at 2005 levels in 2012 before cutting them by 15% by 2020 and 70% by 2050.

After much publicized debate while the bill resided within the Senate Environment and Public Works Committee (EPW), the bill was killed in the Senate during June 2008. It was defeated by a procedural vote (cloture) without undergoing any significant debate on the Senate floor.

Waxman-Markey (HR.2454, American Clean Energy and Security Act of 2009) and Kerry-Lieberman (American Power Act)

The Waxman-Markey bill originally proposed during the Spring of 2009 by House Representatives Henry Waxman (D-CA) and Edward Markey (D-MA). The bill included a combined energy efficiency and renewable energy standard, reaching 20% by 2020. The economy-wide GHG emissions reductions would have been 3% by 2012 (relative to

¹ CO₂ Eq. indicates *carbon dioxide equivalents*. This measure incorporates the differing global warming potentials (GWPs) of the various GHGs (CO₂ has a GWP of 1.0). A tonne is a metric ton, which is about 10% larger than a short ton.

2005 levels), 20% by 2020, 42% by 2030, and 83% by 2050. Heavy industry would not have been covered by the cap until 2014. The bill covered the same GHGs as Lieberman-Warner, with the addition of nitrogen trifluoride. The bill passed the House during June 2009.

In 2010, after the International Copenhagen Summit (COP15), the Kerry (D-MA)-Lieberman (I-CT)-Graham (R-SC) compromise negotiations received a lot of attention, as an alternative to Waxman-Markey in the Senate. The possibility for compromise was sought by this trio of Republican, Democratic, and Independent Senators representing northern as well as southern constituents. Compromise was being crafted around promotion of offshore oil drilling and delaying the implementation of GHG constraints on heavy industry. After Senator Graham pulled out of the negotiations (due to issues pertaining to immigration reform and the BP Gulf oil spill), Senators Kerry and Lieberman introduced the bill, the American Power Act, without Senator Graham. The American Power Act's GHG coverage and proposed emissions reductions were similar to those in Waxman-Markey. Public estimates of their allowance prices were similar also. The bill included a price floor of \$12/tonne CO₂ Eq., increasing at 3% over inflation and a price ceiling of \$25/tonne of CO₂ Eq., increasing at 5% over inflation. Because of the mechanism used for cost containment, the price ceiling could be broken under scenarios such as zero supply of international offsets.

The American Power Act included provisions to encourage the use of natural gas in the transportation fleet, to delay the implementation of GHG policy on heavy industry until 2016 (the rest of the economy would have been required to begin emissions reductions in 2013), to support offshore oil and gas development, and to support nuclear power development.

Little more happened in the Senate with regard to these two legislative proposals during the summer of 2010 as climate change took a backseat to other issues in the public discourse. Since the mid-term elections in the fall of 2010, there have been no major legislative proposals for addressing climate change.

Some State and Regional Level Developments

California's AB32

California's AB32 policy was signed into law by Governor Schwarzenegger in 2006. AB32 requires California to reduce its GHG emissions to 1990 levels by 2020 and 80% below 1990 levels by 2050. The 2020 cap represents an approximate 15% cut below 2012 emissions. The intended implementation schedule would have covered electricity (including imports²) and large industrial facilities in 2012, followed by distributors of fuels and natural gas by 2015.

² The coverage of emissions from out-of-state generators that produce electricity for export to (and consumption in) California is expected to be difficult as a practical matter.

AB32 has been delayed a year and will begin in 2013. California carbon allowances have been trading in the \$15-\$22/tonne for 2013-2014 compliance. The market is thinly traded and is expected to remain so at least until the California Air Resources Board (CARB) approves the final market rules in late October 2011. The allowance pricing in California is indicative of the specific policy design of AB32 and is not necessarily an indicator of the impact of future Federal policy.

AB32 incorporates a variety of flexibility mechanisms such as allowance trading, banking, 3-year compliance periods, and the use of offsets.

Regional Greenhouse Gas Initiative (RGGI)

The Regional Greenhouse Gas Initiative (RGGI) is a regional GHG trading program covering the northeast states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont). Governor Chris Christie (R-NJ) has recently announced the withdrawal of NJ from the program (NJ will cease to be part of RGGI in January 2012). RGGI is scheduled to reduce CO₂ emissions from power plants by 10% by 2018 relative to the 2009-2014 stabilization level. The stabilization level is 188 million tons, which is about 4% higher than the 2000-2005 actual emissions levels.

In recent years, the RGGI prices have been at or near the minimum reserve price of \$1.89 per short ton. With reduced load (in part due to the recession), dispatch economics that are more favorable to natural gas than expected, and banking provisions, allowance prices in RGGI have been at or near the price floor. By 2018, the RGGI cap is supposed to be cut by 10% (to about 169 million tons). Current emissions are well under this level, implying that the RGGI policy will not be binding without revisions to the policy design and/or caps. A stakeholder process for reviewing the current RGGI policy has recently begun.

With respect to RGGI allowance trading during 2010, the average daily volume of RGGI futures trading ranged from zero to 1.3 million. Average daily trading in 2010 was 0.21 million allowances, in comparison to 2.7 million during the prior year. The total volume of trading for all of 2010 was 52 million allowances, in comparison to the 143 million allowances that were auctioned or allocated in 2010.³

Exchange traded volumes have contracted greatly over the last 12 months (to September 30, 2011) on the NYMEX and the CCFE (Chicago Climate Futures Exchange). The CCFE will close at the end of the calendar year 2011, with existing contracts and related trading rolling over to an over-the-counter (OTC) platform on the Intercontinental Exchange (ICE).

³ "Annual Report on the Market for RGGI CO₂ Allowances: 2010," Potomac Economics, April 2011.

International Climate Negotiation Outcomes⁴

Copenhagen Accord at COP15

Going into the Conference of the Parties 15 (COP15) to the UNFCCC held in Copenhagen in December 2009, expectations for progress in the international efforts to address climate change were high. The Copenhagen meeting was a capstone to a process that had begun with the Bali Action Plan two years before. A political accord was struck at COP15. The accord calls for emissions reductions from all the major economies – this includes large developing countries such as China for the first time. However, it remains unclear how a binding agreement will be reached.

The conference in Copenhagen was characterized by discord. There were public divisions and arguments. Notably, at the close of the conference multiple countries were trying to block the Accord because they were outside of the room while it was being negotiated. These countries included Venezuela, Sudan, Nicaragua, and Bolivia. In addition, throughout the conference, there were frequent disagreements on approach between the U.S. and China.

Notably, the Accord included the pledge by developed countries to provide \$100B per year of transition assistance by 2020 to developing countries. The Copenhagen Accord did include broad agreement on emissions verification procedures.

Cancun Climate Change Conference at COP16

Going into the November/December 2010 Cancun Conference of the Parties 16 (COP16) to the UNFCCC, expectations were low (relative to sentiments prior to COP15). At the conclusion of COP16, there was still no clear path to binding commitments for emissions limitations among the participating countries. However, further progress was made with respect to finance and transparency.

COP16 was less acrimonious than COP15 and the negotiations produced small successes breathing some life back into the UN process.

Summary of Recent Legislative Developments

Since the Waxman-Markey and Kerry-Lieberman bills failed during the summer of 2010, the discussion of federal GHG legislation in Washington has largely faded. This stands in contrast to relatively consistent and vigorous debate over the prior several years. Climate change policy was overshadowed by the national Health Care debate. The Republican victory in the House and the narrowing of the Democratic majority in the Senate has suppressed the legislative debate about GHG legislation. With continued sluggish growth in the U.S. economy and high unemployment, action on climate change appears lower on the national agenda than it was just a few years ago. Considerable anti-

⁴ This section is based on summaries written by the Pew Center on Global Climate Change.

regulation sentiment has also developed as part of a broader discussion about the role of government in the U.S. economy. It is against this backdrop that a massive and complex GHG bill would have to advance – a difficult political proposition at this time.

It seems highly improbable that federal GHG legislation could pass before the next federal election. With this mind and with the assumption that it would take at least one year to pass complex GHG legislation after the election, the earliest feasible date for passage is early 2014. Most GHG legislation has a 3-year implementation period, thus the earliest feasible date for implementation would be early 2017.

Recent EPA Actions on GHG Regulation / Implications for Utilities

EPA has entered into a settlement agreement with environmental organizations and several States to issue rules that will address GHG emissions from electric generating units and refineries. For gas-, oil-, and coal-fired electric generators, EPA committed to proposing regulations by July 2011 and finalizing them by May 2012. The July deadline was extended and EPA recently announced that they would not meet the extended deadline of September 30, 2011. EPA will likely negotiate a new deadline with the other parties to the settlement agreement.

When proposed and finalized, the regulations will take the form of New Source Performance Standards (NSPS) for new and modified generators and State emissions guidelines for existing generators. The NSPS will apply to new and modified generators if their construction begins after EPA proposes the NSPS. The states are given significant discretion under the Clean Air Act with respect to the timelines and stringency of applying EPA's guidelines to existing facilities.

CO₂ Price Trajectories from Recent Public Analyses

CRA reviewed the public analyses of recent GHG legislation by the U.S. Environmental Protection Agency (EPA), U.S. Energy Information Administration (EIA), and the Massachusetts Institute of Technology (MIT). The reviewed legislation includes the Lieberman-Warner, Waxman-Markey, and Kerry-Lieberman bills. Results for EPA are reported for both its ADAGE and IGEM models.⁵

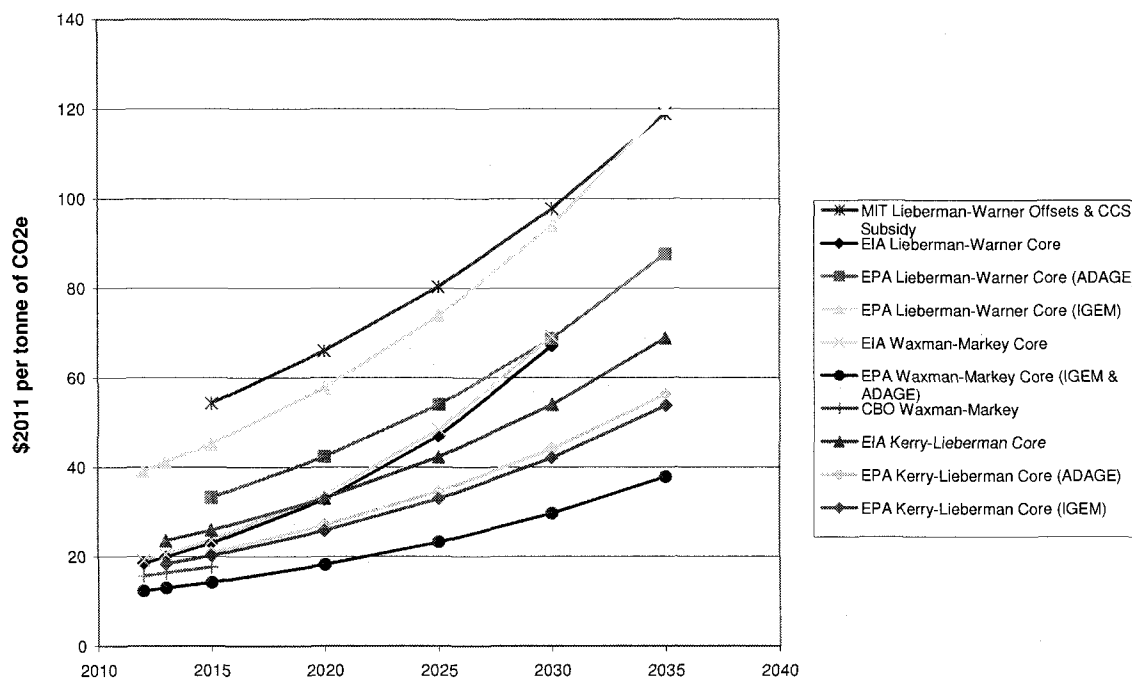
MIT did not evaluate all the bills, so we have only included MIT's Lieberman-Warner analysis. However, MIT did evaluate several GHG trajectories that were approximations

⁵ The EPA models are the Applied Dynamic Analysis of the Global Economy (ADAGE) and Intertemporal General Equilibrium Model (IGEM).

of other bills⁶ – from this analysis, we observe that MIT’s projected allowance prices tend to be higher than those for EIA or EPA.

Exhibit 2 summarizes the “core” cases for the most recent legislation. We have put all of these trajectories into the same units (2011\$ per tonne of CO₂ Eq.).

Exhibit 2. CO₂ Prices for Recent Proposals and Public Analyses



We note that with the exception of the MIT analysis and the EPA Lieberman-Warner (IGEM) analysis, the allowance prices tend to start in the range of \$12 - \$33 per tonne of CO₂ Eq.. The two noted exceptions have higher allowance starting prices. Each price path exhibits the standard feature for a cap-and-trade policy that includes banking, namely the price rises at the model’s discount rate (this price path prevents arbitrage across time).

We also note that these studies have a variety of sensitivity analyses associated with them (not shown) – key sensitivity variables include restriction on technology availability (e.g., carbon capture), energy efficiency deployment, and the availability of international and domestic offsets. We note that the availability of international offsets has a particularly large impact on the allowance price. For example, the EPA’s analysis of Waxman-Markey has a starting allowance price that is 89% higher with zero availability of international offsets.

⁶ Paltsev, et al, *Assessment of U.S. Cap-and-Trade Proposals*, MIT Joint Program on the Science and Policy of Global Change, Report No. 146.

Recommended CO₂ Allowance Price Projection

The future of global and U.S. GHG policy is uncertain. It is not known if federal legislation will ever pass, or if it does, when it will be implemented. The stringency of the caps and the resulting allowance prices are also not known. The co-evolution of climate science, macroeconomic conditions, and electoral politics will ultimately determine the U.S. GHG policy.

Based on our review of the most recent legislative proposals and the CA AB32 policy, we recommend the CO₂ price ranges below for the duration of APS's 15-year planning horizon. As was shown in Exhibit 2, most of the starting prices associated with public analyses of the most recent bills are clustered in the range of \$12 - \$33 per tonne of CO₂. However, this report has discussed the factors that lead us to recommend somewhat lower starting allowance prices. These mitigating factors include slowing of progress in international negotiations and the current U.S. political and macroeconomic conditions. These conditions suggest that future bills might be less strict/aggressive. We also suggested that early 2017 is the earliest feasible date for the implementation of federally legislated GHG policy – we feel it is prudent to expect implementation a year or more beyond 2017. Our recommendations are as follows:

Base Case. For the IRP's base case, we recommend using \$12 (2011\$) per metric tonne of CO₂ Eq. beginning in 2018-2020 and rising at 5% above inflation. This trajectory is highly plausible and represents a reasonable base case for planning.

Note that under cap-and-trade, CO₂ prices are typically projected to rise at the discount rate applicable to the business operations impacted by the CO₂ market. For example, if CO₂-emitters looked forward 3 years into the futures market and saw that the CO₂ price was higher than the discount rate would suggest, they would further cut emissions now and bank them to reduce compliance costs 3 years from now. The result, in aggregate, would be to push up current allowance prices and depress future prices. Given this type of calculation by market actors occurring over 40+ years, the price rise will tend to equilibrate at the discount rate. CRA assumes a 5% real discount rate applies to the cap-and-trade market, which is in line with other studies which typically are in the 4-7% range. A real discount rate reflects the rate over and above the general economy-wide inflation rate. In actual practice, changes in technology, fuel prices, energy demand, caps, and other parameters will yield actual prices for CO₂ that will vary over time.

Low Case. Given the current macroeconomic and political climate, we also believe it makes sense to consider a plausible scenario in which federal climate legislation is not enacted in the U.S. for decades.

High Case. We also believe it makes sense to evaluate a higher carbon price trajectory, for example \$20 (2011\$) per metric tonne of CO₂ Eq. beginning in 2018-2020 and rising at 5% above inflation. We do not believe this is the highest carbon price trajectory that is politically feasible, but it represents a reasonable upper bound to reflect probable policy over the next decade.

We also suggest to APS that it would be reasonable – depending on the horizon of the analysis - to assume a limit on the allowance price above which it could not rise any further (most relevant for the \$20 high case). It seems likely that there is a price above which political support for a GHG policy (assuming one could pass) would deteriorate.

We also note that under GHG policy, natural gas prices will likely rise (relative to a business-as-usual forecast) in the short- to medium-term as the electric sector consumes more gas. In the long-term (after APS's 15-year planning horizon), the natural gas prices (exclusive of the CO₂ price) will likely fall (relative to a business-as-usual forecast) as advanced, low-carbon technologies enter the market in large-scale (e.g., carbon capture, new nuclear, etc.). With respect to the demand for electricity, a CO₂ price also will generally dampen the demand for power below a "business-as-usual" load forecast.

CO₂ Allocations to Utilities

The allocation of GHG allowances under a cap-and-trade program is one of the most contentious parts of climate change policy. The allocations represent the division and transfer of wealth. The government has the choice of 100% allowance auction, 100% free allocation, and all options in between. Moreover, the government can select the distribution of the free allocations, that is, the recipients of the transferred wealth. Because the possibilities for allocation design are limitless, potential recipients are put into the position of advocating for the most beneficial allocation. Allocation schemes are by nature contentious and arbitrary.⁷

Generally, the allocation scheme does not affect the compliance choices of energy producers and consumers. Exceptions to this generalization include: (1) the uses of auction revenue can alter decision-making (e.g., to reduce other taxes on capital and labor), (2) free allocations to cost-of-service utilities can lower electricity rates and therefore reduce the role of demand reduction in GHG compliance, and (3) the potential for market power (e.g., if all allowances were freely given to one party, market power would distort the production decisions).

The allocation that a particular generating unit would receive under a federal CO₂ policy in a particular year would be based on: (1) the cap itself, that is, the fractional reduction in emissions represented by the cap (e.g., if the cap were zero, then all units would receive zero allocation), (2) the fraction of total allocations distributed to the electric sector versus other sectors (and versus auctioned), and (3) the allocation among units within the electric sector, typically based on historic emissions. As the cap is tightened, the dollar value of each allowance increases.

⁷ In the non-carbon context, EPA's recently finalized Cross-State Air Pollution Rule (CSAPR) allocated units with SO₂ and NO_x allowances primarily based on heat input. The final rule marked a significant departure from the proposed Clean Air Transport Rule (CATR) which allocated allowances based on historical emissions. The final CSAPR allocation benefits cleaner units at the expense of more heavily polluting units. This has been a contentious aspect of the CSAPR final rule.

The electric sector typically represents 35-40% of U.S. GHG emissions. The Lieberman-Warner proposal distributed 20% of total allowances to power plant owners and about 10% to load serving entities (LSEs) in 2012. Thus, the power sector was to receive allocations for roughly 80% of its emissions-based share $([10\% + 20\%] / 37.5\%)$. By 2031, the power plant owners would have received none of the total allowances.

Under Kerry-Lieberman, about 74% of the allocations were to be freely distributed in 2013. By 2035, no allowances would have been freely allocated under Kerry-Lieberman. Of the freely allocated allowances, the Kerry-Lieberman bill would have freely allocated 51% of the allowances to the electric sector in 2013-2015 (before heavy industry is placed under the cap), 35% in 2016-2026, before tapering off to zero by 2030. Prior to 2027, the electric sector would have received slightly less than its emissions-based share.

As discussed above, the allocation of allowances is complex, arbitrary, and difficult to predict. One reasonable scenario would be to assume that the electric sector would receive 80-90% of the allowances that it needed during the first year of GHG policy implementation, and then reducing that quantity of allowances (tonnes) linearly to zero over the subsequent 20-year period. The value of these allowances (\$) for the APS portfolio in any year would be equal to the number of allocated tonnes times the allowance price.

While the allocation of allowances to APS under any climate-change policy would be an important component in estimating the ultimate impact to APS electric rates, decisions related to future APS generation resources will be based on applicable CO₂ prices (along with demand growth, fuel prices, etc.). This is because allowances can be bought or sold at the prevailing market price. As such, any allowances provided to APS would not change the most economic resource expansion policy to pursue, notwithstanding impacts on demand growth.

Perspectives on Clean Energy Standards (CES)

Clean Energy Standards (CES) are similar to Renewable Portfolio Standards (RPS) except that natural gas-fired generation and nuclear power would be included in the mandated requirement. Typically, only a portion of the gas-fired generation would count toward the CES requirement.

The CES policy is a mandate for low-carbon power. The CES would result in a price for clean energy credits that power producers would consider in their generation decisions. For example, the CES credit price might encourage a generator to dispatch gas before coal, thereby creating a credit for CES compliance or sale. In contrast, a cap-and-trade policy or a carbon tax provides an economic disincentive to generate CO₂. While the two approaches are fundamentally different, a CES could conceivably be designed to roughly result in the same future generation mix as a cap-and-trade policy or a carbon tax. To achieve this comparability, one of the key choices in the CES policy design would be the treatment of gas-fired generation. If the objective of the policy is to reduce CO₂

emissions, a carbon tax (or cap-and-trade) would typically be a more direct and efficient means of doing so. In general, the CES would be a less direct method of reducing CO₂ emissions.